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Electric Light & Power
THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

WEPCo named Electric Utility of Year

BARRINGTON, IL—Wisconsin Electric Power Co., which serves three territories in Wisconsin and the Upper Peninsula of Michigan, has been chosen Electric Utility of the Year for 1982. The announcement was made by *Electric Light & Power* magazine Editor-in-Chief Robert A. Lincicome.

The Milwaukee-headquartered utility was selected for its overall performance on behalf of its customers, shareholders and employees. Specifically, Lincicome said, WEPCo was chosen because of its strong financial performance in 1982 and for its successful efforts to rebuild its financial foundation, get long-term programs under control and put itself in a position to make decisions affecting its future based on the merits, rather than on expedition or political necessity.

A special report on Wisconsin Electric Power Company and its award-winning operations begins on page 9.

Lincicome said that the company's early recognition of changing growth trends and its success in dealing with a state regulatory commission that historically has been rated by analysts as "difficult" were important factors in company management's abilities to gain better control of its own future prospects than many other utilities are capable.

WEPCo has curtailed its construction program to the point where it anticipates no new additions until 1992 beyond the three projects now being finished. As a result, the company believes it will be able to meet 93 percent of its construction fund requirements, and 69 percent of total capital needs, from internal generation.

WEPCo's heavy emphasis on two-way communication with its publics—customers, shareholders and employees—also was rated heavily in the decision, along with the company's two-year budgeting procedure that allows rate increases to begin with the start of the target year, instead of part way through the year.

The Wisconsin utility, which serves some 2-million people in its three operating territories in the industrialized Milwaukee-Southeast Wisconsin; Appleton (WI) and Upper Peninsula (MI) areas, is the 14th electric utility to earn the award since inception of the program in 1969. Last year's winner was Atlantic City Electric Co.

Wisconsin Electric Power Co.'s Point Beach nuclear power plant, shown in a night photo above, is considered by company management to be one of the company's best investment decisions. Total production cost for the plant is 0.95¢ per net kWh, a third the cost of fossil fuel generation. WEPCo has been named EL&P's 14th annual Electric Utility of the Year.

Clinch River site work is underway, but continued funding is threatened

GAO says costs could rise to $8.7 billion

Dan Utroska
Associate Editor

WASHINGTON, D.C.—Preliminary field work actually has begun at the site of the proposed Clinch River breeder reactor in Tennessee, but the efforts of opponents to kill the project continue just as strong as ever.

At press time it appeared likely that opposition Congressmen would be able to marshall enough votes to kill funding for the project when the Clinch River appropriations bill comes to the floor of the House of Representatives during the lame duck congressional session convening after the November election.

The authorization to begin preliminary site work, granted by the Nuclear Regulatory Commission on August 5, had been challenged in U.S. courts in both Atlanta and Washington, D.C., but on September 22 the last of a spate of judicial decisions was rendered, and the Department of Energy was finally permitted to start the bulldozers moving.

The court challenge in Atlanta by the Natural Resources Defense Council was aimed at nullifying the decision by the Environmental Protection Agency in that city to issue a water discharge permit for the Clinch River site before completion of an environmental impact statement. NRDC argued before the court that the granting of a National Pollutant Discharge Elimination System (NPDES) permit before issuance of the impact statement was illegitimate.

The district court in Atlanta agreed and issued an injunction prohibiting any site clearing work. But when the Department of Energy took the matter to the U.S. Court of Appeals for the Eleventh Circuit, it was decided that the Court of Appeals for the District of Columbia Circuit was the more appropriate place to litigate the matter and so the lower court ruling was overturned on jurisdictional grounds, a spokesman for NRDC said. On September 22, therefore, the way was cleared for DOE to start preliminary construction work in Tennessee.

The Natural Resources Defense Council, responding to the court's

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California PUC contemplates partial rate treatment for SCE's San Onofre-2 unit

SAN FRANCISCO—The staff of the California Public Utilities Commission is contemplating a rate scheme that would allow Southern California Edison Company to recover only about 60 percent of its investment in the San Onofre-2 nuclear plant when that unit becomes operational.

Under the plan, the remaining 40 percent would be recovered if and when an independent audit verified that all construction expenditures had been prudently incurred.

While the CAPUC proposal on base rate treatment for San Onofre-2 has not yet been offered in evidence in commission proceedings, it is noteworthy that the state agency is contemplating such an action against a backdrop of growing regulatory reluctance to authorize full, traditional rate base treatment for large base-load generating plants. *EL&P* has reported the growing desire of some commissions to alleviate "rate shock" and to confirm the prudency of the huge expenditures being incurred by

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Creative funds ease deserted plant write off

SALEM, ORE—Portland General Electric company will use nearly $65 million in proceeds from a debt-equity swap to help pay for the costs of its now-abandoned Pebble Springs nuclear plant.

The move has been prompted by the interpretation of state statutes by the Oregon Public Utility Commissioner. John Lobdell says that state law prohibits the recovery from ratepayers of costs sunk in abandoned power plant projects.

In a debt-equity swap, an investment banking firm buys up numerous issues of a company's low coupon bonds, and after calculating how many shares of that company's stock will be required to offset the retired debt (factoring in some other costs), it offers the bonds for retirement by the utility in return for shares of new stock. The banking firm then turns around and sells these shares on the open market.

The utility is able, through such a deal, to pick up the difference between the face value of the retired securities and the price the investment banking firm paid for them. The utility can thereby avoid the taxes on the gains it would otherwise have had to pay if it had retired the outstanding debt on its own.

Earlier this year, the Oregon utility commissioner required Portland General Electric, principal owner of Pebble Springs at 47 percent, and Pacific Power & Light, a co-owner at 29 percent, to write off their investments in what Lobdell then called "two dry hole nuclear projects."

According to commission figures, PGE's share of the project's sunk construction costs total nearly $132 million. In addition to applying the proceeds from the debt-equity swap, the utility will put up $10.8 million gained through its leasing of federal tax credits. In addition, the company's tax liability will be reduced by $44.4

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Foreign Power Briefs

- **France** will construct a plant to produce fuel for nuclear plants operating under the pressurized water reactor system. The government approved plans for the plant which will be built by Cie. Francaise des Combustibles, a jointly owned subsidiary of the state-controlled Cie. Generale des Matieres Nucleaires and Framatome, the nuclear equipment subsidiary of Creusot-Loire S.A., the heavy industry group. Completion of the plant is scheduled for late 1983. It will be located near nuclear plants at Pierrelatte and produce 1,250 tons of nuclear fuel annually.

- **Victoria, Australia's** state electricity commission will borrow nearly $3 billion over the next few years to finance the Loy Yang generation project. Eight 500 MW coal-fired turbines are to be installed by 1993. The commission has already raised about $1 billion of the estimated $4 billion needed to complete the project.

- **Britain's** Central Electricity Generating Board (CEGB) has chosen the Hinckley Point nuclear station in Somerset as its next nuclear site after Sizewell B. The CEGB is seeking approval to make Sizewell B the first British station to use the Westinghouse/SNUPPS pressurized water reactor. Hinckley C would then be the second plant to use the Sizewell design.

- **Ontario Hydro** and a group representing about 5,500 management and professional staff have negotiated a voluntary program to help cut the Canadian utility's 1982 payroll costs. Employees can choose to take an unpaid leave of absence, additional unpaid vacation time, work a four-day week at 80 percent pay, or volunteer to work additional hours without pay. The program will last until the end of the year.

- **A Swedish** electrical equipment manufacturer, ASEA AB, has announced that it is backing-out of a billion dollar power project in Zaire. Company officials report that the government of Zaire owes ASEA more than $60 million and has failed to maintain contractual payments. ASEA had asked for immediate payment of $12 million to continue with the project.

- **FERC** recently approved agreements between Hydro-Quebec and a group of eight New England utilities that will clear the way for construction of a high voltage transmission line in Vermont or New Hampshire. The New England utilities estimate that the line could save the companies about 7.5 million barrels of oil a year and eliminate the need to construct 500 MW of reserve generating capacity. They say it could be operable by 1987.

- **A group of Swedish** companies and Allis-Chalmers Corp. have combined to form Fluidcarbon Sweden AB, which will produce and market a coal-water mixture as a fuel for utility and industrial boiler applications. Developed by Swedish scientists, fluidcarbon fuel is made up of roughly 75 percent coal, 1 percent additive and water. Extensive testing has confirmed that the fuel functions commercially at a cost approximately 20 percent less than for conventional oil fuel.

- **Rhapsodie,** France's first experimental fast breeder reactor has been shut down permanently. The French Atomic Energy Commission said studies showed repairs of an internal nitrogen leak would be too "complicated, long and costly." Rhapsodie first went into operation in 1967. The Commission said the reactor "has already fulfilled its objectives."

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EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (••). All readers receive EL&P's industry news section.

GAO: U.S. can't handle big emergency outages

Don Minner
Assistant Editor

WASHINGTON, D.C.—Federal and state governments are not adequately prepared to handle a major electrical emergency, says the General Accounting Office.

"The utility industry has demonstrated the capability to manage and restore service in most instances of power outages caused by accidents, weather, equipment failures, and human error," said the GAO in a recent report. "However, should the nation or region suffer a major, long-term power disruption caused by war, sabotage or terrorism, the consequences would most likely have national impact."

The GAO chastised the Department of Energy for not putting together an emergency program. "Considering that more than 16 months have passed since our recommendation that DOE develop a program, we believe DOE could have done much more," the GAO said.

In earlier reports, the GAO had urged the Energy Department to develop programs to handle national electric emergencies.

DOE protests

An official at DOE heatedly protested the way in which the GAO prepared the report. "The report speaks for itself," said Rich Weiner, director of the Office of Energy Emergency Operations, "It's an extraordinary poor work."

Weiner said that GAO sent over two "incompetent auditors who didn't know the first thing about the subject" they were investigating. He says he saw them in the operations office twice for a total of about 4 hours.

DOE has not revised its electric emergency handbook, developed or conducted any training programs and the GAO says that no substantial planning has been done.

But Weiner says the GAO did not fully look into all the plans his office is preparing. "I have a milestone schedule and all our deadlines are being met," exclaimed the director. "We are proceeding well on the different plans."

Budget cuts also will have an affect on emergency preparedness programs, notes the report. The proposed budget for 1983 is nearly half of what it was in 1982 and 22 staff members are to be dropped.

Work continues

That, says Weiner, is the only bit of truth in the report. He said his staff will be cut, but work will continue and continue to be on time.

Although many states have laws which give the governor power to act in an electrical emergency, the report says most do not have any specific plans detailing how power would be restored quickly and effectively.

"Should a major regional disruption occur, individual states would not be able to effectively handle the situation," notes the report. "...an action by one state may adversely affect another state because the electric power is not tied to state jurisdictional boundaries."

According to Weiner, individual utilities are prepared and know the best way to restore power in their systems, so the Federal government should not tell them how to do it.

"Our major problem is national defense," he said, "We are working extremely close with the intelligence community and electric utilities to determine who is capable of causing a flow-through disruption—one that endangers the defense of the country."

Out of 11 states contacted by the GAO, none had any form of plan to deal with a major electrical emergency. Florida does have a plan for statewide emergencies that was developed with the aid of a Florida utility industry group.

The GAO report points out that California, Georgia, Texas and Illinois rely completely on the utilities to handle any statewide emergency.

Attacks

Rep. Berkley W. Bedell (D-Iowa), chairman of the House Small Business energy committee, requested the GAO study the matter after witnesses testified in May about attacks on electric facilities.

Amory Lovins, the "soft energy path" proponent, testified about farmers in northern Minnesota who have shot out insulators and knocked over transmission towers because power lines were planned to run over their property.

And another witness testified of a 1980 raid on a house in New York that uncovered detailed plans of New York's electrical system.

Bedell said it is unwise to "ignore the very real possibility that simple acts of sabotage and terrorism could shut down our electric power system and bring our society to its knees."

As an example, the GAO points to the recent sabotage of a substation on Vancouver Island, Canada. The substation was still under construction, but the damage was extensive enough that the utility may have to ration or allocate power until it can be rebuilt.

"This is ridiculous," sighed Weiner, "We have the complete support of the electric utility industry and every agency we work with. I would think the GAO could find a better way to spend their money."

APS reduces '83 operating budget

PHOENIX—In an effort to reduce 1983 operating expenses, Arizona Public Service Company (APS) has announced measures to trim over $14 million from its budget.

Some of the measures were prompted by recommendations in a recent independent audit of APS' management and operating procedures.

The company said its cost control efforts will involve phase-out of some local customer service centers, decreases in personnel through attrition and early retirement.

A one-time voluntary early retirement program will be offered to employees who are at least 55 years old and have 20 or more years service with APS.

"The program will enable us to evaluate our manpower requirements, streamline our organization and reduce company expenses at a time when we are exploring every cost-saving avenue available," said Mark De Michele, executive vice president for customer, employee and corporate relations.

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How to prolong steam generator life in nuclear plants

S.Frank
R.P. Wessel
W.B. Dodson
D.A. Piccione

Stone & Webster

Nuclear steam generator design life is 40 years, but replacement may be required in 10 years or less. Can corrosive failure be averted and operating life extended? This question is being asked by many utilities about steam generators in pressurized water reactor (PWR) nuclear power plants.

Defining the problem

Steam generators in PWR plants world-wide are experiencing problems that are reducing both operating life and overall plant availability. In 1981, 26% of non-refueling outage time was caused by steam generator-related problems. Practically all problems occur on the secondary (steam and feedwater) side of the steam generator tubes.

The first serious problem occurred in 1973, when severe thinning (wastage) of Inconel 600 tube walls became evident in several recirculating steam generators. In 1974, to prevent further tube wastage, the industry began switching from phosphate secondary side water treatment to all-volatile treatment (AVT), using hydrazine and ammonia. (Only AVT water chemistry has been utilized in once-through steam generators. Problems in once-through steam generators result primarily from mechanical factors which relate to internal steam generator design and which are not addressed in this article.)

But in 1975, denting of steam generator tubes at the carbon steel tube support plates was discovered. By 1979, other problems such as U-bend cracking, intergranular attack, stress corrosion cracking and pitting were found to be affecting steam generator tubes. A description of the various corrosion problems is given in the table.

Denting, which can lead ultimately to cracking of a tube, is the most serious problem encountered in steam generators to date. The major constituents in the electrochemical processes leading to the formation of nonprotective magnetite (Fe_3O_4) at the tube-to-support plate crevices are chlorides, copper, and oxygen. Since the oxide does not act as a protective layer, corrosion continues; and since the oxide occupies more space than the parent metal, squeezing, or denting, of the tube from the outside occurs.

Denting was the principal reason steam generators at the Surry and Turkey Point nuclear power plants had to be replaced. Limited success has been achieved in arresting tube denting. Chemical cleaning has yielded mixed results, while plant and operational improvements to preclude denting have proven to be costly and time-consuming.

"Replacement may be required in 10 years or less."

Most of the other problems listed in the table occur in the region just above the tubesheet where sludge accumulates, resulting in corrosion of the Inconel 600 tubes by pitting, wastage, intergranular attack and cracking. Maintaining the tubesheet region free of sludge is difficult. Plant system changes and steam generator design improvements are needed to keep the tubesheet region as free as practicable of stagnant contaminants. Stress corrosion cracking of improperly mill-annealed Inconel 600 tubes is the only corrosion problem initiated on the primary side. This problem, as well as other mechanical problems such as fretting (vibration-induced wear) and fatigue cracking may be avoided by improvements in steam generator design and fabrication.

Plugging tubes

When tube deterioration has been identified (for example, by periodic eddy current testing), corrective action must be taken. Plant technical specifications provide a limit for wall degradation beyond which tubes must be removed from service by plugging. Permissable degradation is based on the minimum wall thickness required to provide adequate structural margin during normal operations and postulated accident conditions. Plugs are installed at both the tube inlet and the tube outlet.

Large numbers of tubes may be plugged and removed from service in order to avoid steam generator tube rupture. Plugging results in a loss of heat transfer surface; however, most designs have excess surface area, so that significant reduction in plant power level occurs only after 20 to 25% of the tubes has been plugged.

"Can corrosive failure be averted and operating life extended?"

Some utilities have chosen to repair tubes by sleeving instead of plugging. In sleeving, a tube of smaller diameter is inserted inside the damaged tube. The sleeve is positioned to cover the degraded portion of the original tube, and is then expanded above and below the degraded region.

Sleeving repairs have been performed on the straight portions of tubing within and just above the tubesheet, after the tubes had experienced wastage, pitting, intergranular attack, or stress corrosion cracking. Although adequate for these purposes, such repairs are not practical for tubes affected by denting.

A number of factors must be considered before a decision is made to use sleeving for repair. The remaining life of a plant must be evaluated against the costs required to complete steam generator repair. The expected life of a sleeve must be considered also. There has not been any significant operating experience with sleeved tubes, so the success of this method has yet to be determined.

Radiation exposure to workers during installation of sleeves is a concern. For example, radiation levels on the primary side of the tubesheet have been estimated at the Ginna plant to be 21 R. Sleeve repairs were made to 6500 tubes at San Onofre Unit 1 and resulted in a total exposure of 3500 man-rem. As a comparison, exposure for steam generator replacement at Surry 1 and 2 and at Turkey Point 3 has ranged from about 1760 to 2150 man-rem.

Operation, maintenance changes

The routine operation and maintenance activities at a plant can significantly affect steam generator life and plant availability. These activities must focus on monitoring and controlling secondary side water chemistry if steam generator life is to be prolonged.

A thorough and firmly instituted water chemistry program is required. This involves monitoring key parameters at critical locations, maintaining secondary side water chemistry requirements during layup, startup, and normal operation, and evaluating water chemistry data. The evaluation must quantify benefits of techniques used to limit contaminant levels, locate sources of impurity intrusion and determine appropriate corrective action when specified limits have been exceeded.

The importance of proper secondary side water chemistry is often overlooked during an outage. Shutdown is a period of significant corrosion activity. Therefore, water chemistry must be carefully monitored and controlled during these periods, as

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STEAM GENERATOR CORROSION PROBLEMS

Problem	Description	Plants reporting serious effects
Wastage (Thinning)	Reduction of wall thickness of Inconel 600 tubing in the region above the tubesheet where acid-phosphate sludge exists.	26
Denting	Crimping of tube diameter caused by progressive formation of oxides in annular region between the tube outer wall and the tube support plate.	33
Tube Cracking		
U-Bend Region	Cracks originating in region with excessive ovality, assembly stresses or improper heat treatment during fabrication.	12
Tube Sheet Crevice Region	Cracks initiated in the stagnant crevice region by corrosion mechanisms such as IGA or SCC or as a result of improper tube rolling techniques.	18
IGA–Intergranular Attack	Corrosive attack of grain boundaries in Inconel 600 tubes with no preferential (stress related) orientation.	8
Pitting	Localized attack on tubing resulting from nonuniform corrosion caused by formation of local corrosion cells.	6
SCC–Stress Corrosion Cracking	Intergranular grain boundary cracking of stressed Inconel tubes.	26

> *"Changes in procedures and equipment can be effective, however, they may not preclude replacement with improved designs."*

Steam generator . . . continued from page 31

well as during normal operation.

Clearly, the condenser is the major potential source of air and cooling water leakage into the plant secondary side. Detection and rapid correction of condenser leaks are, therefore, essential. A short-term advantage may be gained by continued power generation when leaks exist which cause specified water chemistry limits to be exceeded; however, this advantage can be easily offset by costly long-term corrosion.

A leak detection system should be used routinely to locate air leaks. Periodic eddy current inspection of condenser tubes and preventive plugging are necessary if cooling water inleakage during operation is to be avoided. Water leaks can be found by utilizing a sensitive leak detection system with a water box drained.

Steam generator cleaning

Various cleaning techniques can be employed periodically to remove impurities from the steam generator during an outage. In steam generators with concentrated contaminants in tube-to-tubesheet crevices, low temperature depressurization flushes should be performed. This procedure has been used in the U.S. and Japan. It involves heating (by electrical resistance or reactor coolant pump heat) a volume of water just above the tubesheet while maintaining a nitrogen overpressure, then releasing the nitrogen. The resulting rapid boiling has been successful in dislodging solid and soluble impurities from the crevices.

Boric acid soaking and maintenance of residual concentrations during operation have also been used at some plants. The intent was to combat denting. Some success has been achieved, but incidence of increased pitting is now being investigated. Therefore, use of boric acid has yet to be proven, as do a variety of other chemical cleaning methods.

Water soaks at high temperature are useful in removing soluble contaminants from steam generators during shutdown. Sludge lancing has also been effective in breaking up accumulations of solids on the tubesheet and facilitating their removal.

To be effective, each of the operating and maintenance activities requires a detailed written procedure, incorporated into a regularly scheduled program, with specific operator training. Such a program improves understanding of steam generator problems and their prevention. The program also permits engineering review of considerations such as compatibility between system materials and water chemistry.

There are a number of improvements which can be made to operating plants which will aid in prolonging the useful life of their steam generators. It is anticipated that all or part of the modifications discussed below could be accomplished during a normal refueling outage.

The blowdown system removes dissolved solids and corrosion products (sludge) from the steam generator secondary side. It also removes nonvolatile radioisotopes when leakage from primary to secondary side occurs. Impurity removal is usually through a horizontal perforated tube leading to two, diametrically opposed, blowdown nozzles, located just above the tubesheet.

Controlling the concentration of dissolved solids and sludge is important in maintaining water chemistry within specification over the full range of operating conditions and thereby in limiting corrosive attack of steam generator materials.

Adequate steam generator protection requires a blowdown system capacity of 1 percent of the maximum steaming rate (MSR) for maximum continuous blowdown. This rate should be used during startup, shutdown, and upset conditions, such as condenser leaks. Consideration should be given to increasing the blowdown capability to 1 percent MSR in all plants with recirculating steam generators as a necessary means for controlling sludge buildup. In some cases, this can be done by simply opening a valve more widely, or, if the pipe size from the steam generator blowdown nozzle has been reduced, replacing it with larger pipe.

In addition to blowdown rate, heat recovery and water recovery are considerations that affect selection of blowdown system configuration and equipment. The cost of equipment to recover thermal energy in the blowdown must be balanced against a reduction in plant thermal efficiency. The cost of equipment to clean up the blowdown and recirculate it to the condensate system must be balanced against the cost of makeup water and waste treatment equipment if the blowdown is discarded.

Layup practices

Maintenance of good secondary side water chemistry is important during periods of plant shutdown, just as it is during normal operation. To protect the steam generator internals from corrosive attack during these inactive periods, the steam generator should be maintained in a wet layup condition.

Wet layup is achieved by filling the steam generator secondary side with deoxygenated, chemically treated feedwater. Since reliance on thermal currents to circulate the water within the steam generator is ineffective in providing thorough mixing of the oxygen scavenging and pH control chemicals, a forced circulation system is needed. It should be capable of circulating secondary side water so as to mix steam generator chemicals uniformly and thereby reduce corrosion.

The wet layup system has other uses such as draining and filling the steam generators. It also works in conjunction with the steam generator nitrogen system to ensure exclusion of oxygen from the steam generator internals. A low pressure nitrogen blanket is maintained above the level of water in the steam generator during wet layup.

Only a visual inspection of the interior can verify the effectiveness of steam generator-related improvements.

Inspection ports, placed to allow visual access to the critical areas of the steam generator, are relatively easy to install and should be added. Installation basically consists of drilling holes through the steam generator shell and providing closure covers for normal operation.

Inspection ports also can provide access for cleaning operations and, in some designs, can function as connection points for improved blowdown, wet layup and fill and drain systems.

Water chemistry control

AVT water quality specifications require precise monitoring and control of chemical concentrations in the parts per billion range. Relatively minor perturbations in water chemistry can cause the specified limits to be exceeded unless the plant is equipped with a precision monitoring system, a hydrazine (for oxygen removal) management system, a condensate polisher, and either a leak tight, deaerating condenser or a deaerating feedwater heater, or both. Furthermore, stringent water quality control is necessary not only during normal operation but also when the plant is shut down, in a transient condition, or operating at part load. During startup, for example, feedwater should be recirculated without being introduced into the steam generators until water chemistry is within required specificatins for normal operation.

Leakage of air and cooling water into the condenser has been a major source of impurities leading to steam generator corrosion. Condenser operation must, therefore, be evaluated when measures for prolonging steam generator life are considered.

A two-pronged approach to combat condenser air leakage is advisable:
1. Detect and plug leaks
2. Improve the deaeration capability

Typical air leakage locations are the turbine-condenser expansion joint, pipe connections and valves. Condenser deaeration can be improved by upgrading the air removal system, redesigning the tube bundles, or reducing condensate subcooling in the hotwell at partial load and during startup by heating.

If condenser cooling water leakage is found to be causing steam generator degradation, a condenser tube failure analysis may indicate the condenser should be retubed with a more corrosion-resistant material, such as titanium or a high alloy, pit resistant steel. Use of copper in the condenser, as well as in other secondary system components, has been found to promote denting in the steam generator and should be avoided. If condenser retubing is undertaken, attention must be given to considerations such as tube vibration, condenser uplift, condenser performance, galvanic corrosion and the tube-to-tubesheet joints.

Along with condenser tube failure, the tube-to-tube sheet joint has been a major source of cooling water leakage. Special measures to ensure leakage-tight integrity, such as use of a double tubesheet, integrally grooved tube-sheet, or a welded joint, should be considered.

Soluble and filterable impurities in the condensate downstream of the condenser hotwell can be removed by a condensate polisher. If condenser cooling water leakage is minor, the condensate polisher allows the plant to remain on-line while the leak is located and repaired. In the event of massive condenser cooling water leakage, the condensate polisher provides time for an orderly plant shutdown. Thus, the condensate polisher maintains the desired water chemistry under various operating conditions and reduces start-up time by providing more rapid water cleanup. Its use is virtually mandatory if the AVT specification of near-zero solids in the steam generator is to be achieved reliably.

Deaerator

Water quality specifications require very low oxygen concentrations in the feedwater entering the steam generator. A deaerating feedwater heater (deaerator) is the most effective means for removing oxygen over the full plant operating cycle, including startup and load swings when corrosion and oxide deposition reach their highest levels. Although deaerators are used extensively in PWR plants abroad, only two domestic units operating today incorporate a full-flow deaerator.

A utility considering adding such a device to an operating plant faces a major retrofit. A deaerator retrofit will increase steam generator availability and operating life because it will reduce oxygen in the feedwater. However, detailed analyses on a plant-specific basis are required to determine cost of installation and effects on system performance.

Conclusion

Prolonging the useful life of steam generators is of high priority for owners of PWR plants. This applies to utilities with steam generators currently in service, as well as to those with new or replacement steam generators about to begin operation.

Industry investigators agree that secondary water chemistry is a key element in preventing steam generator corrosion problems. Achieving the necessary water chemistry control during all phases of operation may require a program for incorporating significant improvements both in plant operation and maintenance, and in systems and components which affect water chemistry.

Changes in procedures and equipment can be effective in prolonging steam generator life; however, they may not preclude eventual replacement with steam generators of improved design in order to achieve high availability at design output.

Old Hydro plants can be upgraded to provide owners with added capacity at minimum cost

James Gasperini
Paul Johrde
Michael Costa

Westinghouse

Modernizing existing hydro plants can be an economic means of expanding generating capacity and can be extremely cost effective in today's operating environment. At current oil prices the benefit-to-cost ratio of upgrading hydro can be as high as 40 to 1. Typically, older hydro units can be uprated by 15 percent, and many significantly higher.

There are only a few ways to increase hydro plant output—by reducing penstock losses, increasing the amount of water available, raising the hydraulic head, and modernizing the turbine and generator—and some of these alternatives are prohibited by factors such as cost, institutional regulations, or environmental restrictions.

Generator modernization is usually the cheapest and easiest alternative for effecting a significant improvement in hydro capacity and efficiency. The following electromechanical areas offer the greatest opportunities for modernization: stator coil insulation, ventilation and cooling, thermal analysis, and computerized design optimization.

Stator winding replacement

The most common generator uprating modification is replacement of the stator winding, using the existing rotor winding and exciter. If the capacity of the exciter is exceeded due to the increase in field current with load, the power factor of the generator may have to be increased, or the exciter may have to be replaced.

In the example shown in Table 1 the machine had enough margin in the exciter and the rotor winding to permit the indicated uprating. The new stator winding has the same number of turns per coil and the same number of parallel circuits as the original. The epoxy-mica ground insulation has a higher allowable working stress than the old asphalt type and can therefore be made thinner for the same voltage. This allowed the designer to improve the coil in three ways: more and thinner copper strands per turn were used to reduce AC strand loss; total copper volume per turn was increased; and the use of a more complete transposition provided a further reduction in eddy loss.

Several generator characteristics are changed. The short circuit ratio is reduced by 15 percent and all reactances are increased 15 percent when referred to the new base. The exciter ceiling voltage does not change so the response ratio is lower. Since the fixed losses remain the same and the new winding has lower eddy current losses than the original, the total loss does not increase in proportion to the load and, therefore, a higher efficiency is obtained.

Thermal analysis

A review of the performance tests of generators built 20 to 40 years ago will show that most had substantial temperature margins from their guaranteed temperature rises. This is especially true of the rotor winding. Thus, by rewinding the stator using compact epoxy-mica in place of the more bulky asphalt-mica insulation and applying a more effective transposition coupled with thinner copper strands, it is usually relatively easy to gain a 15 percent uprating with the original temperature guarantee.

The original, "cool" rotor winding usually can carry the increased field current associated with the uprating. This is very fortunate because most rotor windings suffer little or no deterioration with time and are seldom replaced.

Once the uprating is determined, based on the most restrictive thermal limits of the rotor or stator windings, the new losses are calculated and the original air coolers checked to determine if the additional loss can be absorbed by increasing water flow. Often the coolers have liberal margins, which can be utilized by frequent cleaning of the tubes to minimize fouling.

Ventilation and cooling

Ventilation tests on old generators have shown that many do not have the air flowing where arrows on the drawings indicate. In fact, the velocity and quantity of air flowing in certain parts has been so low in some cases that only excessive margin in the original design has kept the machine operating. For this reason, a survey of the air flow distribution in a generator and measurements of the velocities in the critical cooling passages should be made a necessary input to uprate calculations.

It is often possible to improve the effectiveness of the ventilation system by providing a new endbell design, adding fan blades to the rotor, replacing fan blades, and directing flow to needed areas by adding baffles.

Mechanical changes

In a typical uprating, many electrical components such as stator windings are replaced with technically advanced designs and materials, but the mechanical components remain the same and are loaded under the higher rating. Certain mechanical areas must be considered in the initial planning stages of an uprating. Table 2 provides a general checklist.

The single most obvious change to the mechanical parts is due to the increase in torque which can be significant since upratings run anywhere from a few percent to well over 50 percent. Components most affected are the spider, the shaft, the stator, and the rim-to-spider and spider-to-shaft connections.

The uprate may or may not involve a change in the turbine. If a new turbine is specified, the generator designer must contend with a number of possible changes. A new normal speed, new runaway speeds, new turbine weights, and new hydraulic thrusts must all be considered as causing a significant change in the reliability of the generator.

Economic analysis

The financial analysis shown in Table 3 is based on an actual uprating of a Bureau of Reclamation unit at Grand Coulee. The technical and economic data are taken from that project but the analysis assumes investor-owned utility economics.

The generating unit had approximately a 45-percent capacity factor and had enough water available to take advantage of a 16 percent capacity uprating. The modernization included a replacement set of uprated epoxy resin high voltage coils, a loop test, refurbishment of the stator iron, and new resistance temperature detectors. Because the wheel had additional margin to accommodate the uprating, no additional turbine work was required.

This financial analysis is in accordance with the Electric Power Research Institute's Technical Assessment Guide PS-1201-SR, July 1979. The time value of money (present worth), fuel escalation, product cost escalation, and the total cost associated with ownership are taken into account. The object of the analysis is to determine the present worth savings and cost of the investment opportunity, approximate investment payback period, and cost-to-benefit ratio of the generator modernization.

The analysis takes into account several financial factors, as well as some specific facts concerning the uprating in question. These factors are shown in Table 3 as items A. through K.

First an analysis base year (the year in which delivery and final payment are made) is assumed and all costs and revenues are present-worthed to that base year at the financial discount rate. The discount

Generator uprate, Seattle City Light

The scope of a hydro generator modernization project can be illustrated by a brief description of work currently in progress at Seattle City Light's Gorge Powerhouse. The installation has three generating units totaling 33 MVA, two installed in 1924 and one in 1929. The units are being uprated to 38 MVA.

New steel core

The modernized generator equipment includes a new, low-loss silicon steel core, a newly designed core-clamping-pressure package that will significantly tighten up the new stator core, and newly designed thermalastic epoxy stator windings. The units are designed to run 10 degrees C cooler than the original units at the higher rating. Stray load losses and stator I^2R losses are being reduced by 94 kW.

At 38 MVA, 97 percent power factor, the excitation requirements will be the same as at 33 MVA, 90 percent power factor, producing no increase in field winding operating temperatures. The winding will have the capability of operating at 40 MVA, 99 percent power factor with no increase in field winding operating temperatures or excitation requirements.

The stator coil copper cross section has been increased approximately 27 percent above that in the original winding to reduce the operating temperatures and stator I^2R losses. The stator coil stranding and winding transposition have been improved to provide a significant additional reduction in stator winding operating temperatures by minimizing the eddy and circu-

Closeup of the restacked core shows pieces of hardwood wedged into the slots to keep the parts aligned.

lating current loss component of the generator stray load loss.

Locking devices installed

Stator winding connections, parallel rings, and main and neutral leads are designed to match the increased loading requirements. Stator winding components are braced with spring-type fillers in the slot wedging assembly to maintain radial pressure on stator coils even after dimensional changes have occurred in slot fillers during normal operation. Locking devices are being installed to prevent axial migration of slot fillers.

Materials improved

Improved materials and design techniques will also be used for stator core laminations, stator vent plates, stator end finger plates, the top end plate and the frame-to-soleplate connections.

rate for analysis purposes is equal to the weighted cost of capital. It is assumed that savings begin the year after delivery. Differential production cost is escalated at a constant percentage each year from 1982. Total cost ownership or value of capacity increase is determined through the use of a fixed charge rate which is applied to the investment each year of its useful life. This approximates the total costs associated with ownership which are incurred each year.

To determine the equivalent capital value of present worth savings, the levelized annual fixed charge from each is present-worthed at the financial discount rate. This value is then compared to the capital expenditure. The cost-to-benefit ratio is the resulting ratio between this comparison.

Following are sample calculations showing how the yearly savings figures in Table 3 were generated.

Differential Production Savings are the savings realized by displacing high cost generating capacity with lower cost generating capacity.

Formulas

Differential Production Savings (1983) = kWh/year X uprating percent X Differential Production Cost (1982) X $(1+F)^N$
where kWh = kW rating X hours/year X capacity factor
where F = Fuel cost escalation = .08
and where N = 1983-1982

The Differential Production Savings are tabulated for each year in Table 3.

Value of Capacity Increase is the amount of revenue for the capital expenditure that must be collected for each year of the plant life in order to pay for the cost of ownership (fixed charges).

Value of Capacity Increase = Estimated Purchased Price of New Capacity (1982) X Fixed charge rate
where Estimated Purchase Price of New Capacity (1982) = additional cost of kW capacity X New Capacity (1982) X $(1+i)^M$
where i = Financial discount rate = .14
and where M = 1982-1983

The Value of Capacity Increase is constant through the life of the investment because a levelized fixed charge rate is used.

Present Worth Savings is calculated by adding the Differential Production Savings and the Value of Capacity Increase.

Present Worth Savings (1982) = Total Savings(1983) X 1/(1+i) (1983-1982)
where Total Savings (1983) = Differential Production Savings (1983) + Value of Capacity Increase (1983)
and where i = Financial Discount Rate = .14

The savings for each year are present worthed to 1982 dollars and are summed (see Table 3).

Equivalent Capital Value of Present Worth Savings is determined by dividing the annualized savings by the fixed charge rate.

Equivalent Capital Value of Present Worth Savings (1982) = Cumulative Present Worth Savings X CRF (i,N) X 1/Fixed Charge Rate
where CRF = capital recovery factor (which annualized the savings at the finanical discount rate for the life of the investment) = .1454984.

A 40-to-1 savings

The capital expenditure is paid back after the first year of use. The equivalent capital value of the present worth savings, $27,452,525, is a staggering sum. The uprating realizes a 40-to-1 savings ratio, an overwhelming justification for a utility to commit its financial resources to the hydro modernization.

(Based on a paper presented at the annual meeting of the Pacific Coast Electrical Association, March, 1982)

TABLE I. CASE STUDY SUMMARY

Actual Unit Information

	Original machine	After uprating
Rotor winding	Class B strap copper	No change
Stator winding	Class B asphalt	Class B epoxy-mica
Rating	108 MVA, 1.0 PF, 13.8 kV	125 MVA, 1.0 PF, 13.8 kV
Overload	15%	15%
Exciter	400 kW, 250 V, 300 V ceiling	Same
Short circuit ratio	1.94 (C)	1.63 (C)
Gen. field current: Rated load	1,220 amps (T)	1,250 amps (T)
Rotor winding temp. rise: Rated load	33.5 C (T)	35 C (T)
Stator winding temp. rise: Rated load	51 C (T)	52.5 C (T)
Losses at rated load	1,863 kW (T)	1,910 kW (T)
Efficiency at rated load	98.3% (T)	98.5% (T)
Stator coil copper	36,060 #	37,490 #
Normal torque	75.7 x 10^6 in lbs	87.6 x 10^6 in lbs

These values are indicative for 9 of the 18 original units. The other 9 units may have different values although the uprating is the same.

(T) Test

(C) Calculated

TABLE II. GENERAL AREAS OF CONCERN FOR MECHANICAL INTEGRITY

	The components are most affected by changes in				
Major components	Torque	Speed	Short circuit conditions	Magnetic pull	Thrust
Frame	X	X	X	X	X
Stator foundation	X	X	X	X	
Core–frame connection	X	X	X	X	
Spider	X	X			
Spider–rim interface	X	X		X	
Rim		X			
Pole dovetail–tip		X			
Field coil		X			
Shaft	X	X		X	
Shaft–spider connection	X	X			
Shaft coupling	X	X			
Bearings		X		X	X
Brackets		X		X	X

TABLE III. UPRATING FINANCIAL ANALYSIS–45 PERCENT CAPACITY FACTOR

A. Kilowatt rating (kW) : 97200
B. Differential prod. cost (M/kWh, year) : 18 82
C. Capacity factor (percent) : 45
D. Uprating (percent) : 16
E. Fuel escalation rate (percent/year) : 8
F. Financial discount rate (percent/year) : 14
G. Fixed charge rate (percent/year) : 18
H. Analysis base year : 82
I. Economic life (years) : 25
J. Installed cost ($, year) : 685000 82
K. New capacity cost ($/kW, year, FCR) : 1000 82 18

Uprating Financial Analysis (1982$)

Year	Differential production savings	Value of capacity increase	Total savings	Present worth savings	Cumulative present worth savings
1983	$1,191,788	$2,799,360	$ 3,991,148	$ 3,501,007	$ 3,501,007
1984	1,287,131	2,799,360	4,086,491	3,144,422	6,646,430
1985	1,390,102	2,799,360	4,189,462	2,827,767	9,473,197
1986	1,501,310	2,799,360	4,300,670	2,546,342	12,019,539
1987	1,621,415	2,799,360	4,420,775	2,296,012	14,315,551
1988	1,751,128	2,799,360	4,550,488	2,073,141	16,388,692
1989	1,891,218	2,799,360	4,690,578	1,874,530	18,263,222
1990	2,042,516	2,799,360	4,841,876	1,697,363	19,960,586
1991	2,205,917	2,799,360	5,005,277	1,539,162	21,499,748
1992	2,382,390	2,799,360	5,181,750	1,397,745	22,897,493
1993	2,572,982	2,799,360	5,372,342	1,271,189	24,168,683
1994	2,778,820	2,799,360	5,578,180	1,157,802	25,326,485
1995	3,001,126	2,799,360	5,800,486	1,056,091	26,382,576
1996	3,241,216	2,799,360	6,040,576	964,740	27,347,316
1997	3,500,513	2,799,360	6,299,873	882,590	28,229,906
1998	3,780,554	2,799,360	6,579,914	808,617	29,038,522
1999	4,082,998	2,799,360	6,882,358	741,916	29,780,439
2000	4,409,638	2,799,360	7,208,998	681,691	30,462,130
2001	4,762,409	2,799,360	7,561,769	627,236	31,089,366
2002	5,143,402	2,799,360	7,942,762	577,929	31,667,295
2003	5,554,874	2,799,350	8,354,234	533,218	32,200,513
2004	5,999,264	2,799,360	8,798,624	492,615	32,693,129
2005	6,479,205	2,799,360	9,278,565	455,690	33,148,818
2006	6,997,542	2,799,360	9,796,902	422,058	33,570,876
2007	7,557,345	2,799,360	10,356,705	391,382	33,962,258
Total				$33,962,258	

Capital expenditure : $ 685,000
Equivalent capital value of the present worth savings : $27,452,525
Cost to benefit ratio : 1:40.1

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Incentive rate of return orders should specify how money costs are to be recovered, says NY regulator

Dan Utroska
Associate Editor

ALBANY, N.Y.—Incentive rates of return schemes being mandated or considered by public service commissions should be drafted to explicitly detail how companies building large power generation plants will be allowed to recover capital carrying costs in the future, a state regulator has said here.

According to New York commissioner Richard E. Schuler, if a commission implementing an incentive rate of return (IROR) spells out in advance the rules regarding how the state agency will treat ratepayer repayment of interest charges on borrowed construction money, then it will more fully provide a rate scheme that is less dependent on changing regulatory attitudes and more a function of utility management efficiency.

Schuler is generally credited with translating the incentive rate of return idea from the oil industry to the electric utility industry. Simply put, this incentive plan seeks to reward electric company shareholders if a utility can complete a power plant project for less than an established, agreed-upon cost target. Conversely, shareholders are penalized if a utility finishes plant construction above the target cost.

The New York Public Service Commission is the first state agency in the nation to actually implement such a scheme, although other jurisdictions around the country are currently considering the idea in an effort to rein in runaway power plant construction costs (see *EL&P*, October, 1982, page 1). A target cost completion figure of

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Reagan picks Interior's Hodel to succeed Edwards at Energy

WASHINGTON, D.C.—Quietly, and without much fanfare, Donald Hodel was sworn in as acting energy secretary early in November, succeeding James Edwards.

Unlike those who preceded him, Hodel is an expert on energy matters. For 6 years, he headed the Bonneville Power Administration.

Hodel, a 47-year old lawyer who was second in command at the Interior Department, immediately came under fire from environmental groups because of his friendship with Interior Secretary James Watt.

Denny Shaffer, Sierra Club president, said, "America does not need a second James Watt in the Cabinet."

Friends of the Earth said, "The symbolism of giving Watt's deputy a seat on the Cabinet is incredible."

Chairman of the House Energy Conservation and Power Subcommittee Rep. Richard Ottinger (D., N.Y.) said, "I hope the 'Under New Management' sign on the department means more than just the same old stew dished out by a new cook."

At press time, Hodel had not been permanently nominated for the appointment, but it was expected to occur during the lame-duck session of congress that began Nov.29.

White House spokesman Larry Speakes announced Hodel's appointment, but neither Hodel or Reagan was present.

Cherokee 2 & 3 cancelled

CHAROLETTE, NC—Add Cherokee Units 2 & 3 to the growing list of nuclear unit cancellations.

Duke Power Company Executive Vice-President W.H. Owen said the two 1280-MW units at the Cherokee Nuclear Plant in South Carolina were dropped because of "lower growth and demand than when initially planned. The need for these units has stretched out beyond our current planning horizons."

The utility had projected a 7 percent annual growth when the units were planned, but that has since declined to only 2 percent a year.

Approximately $68 million has been spent on both units. They were delayed in 1980 and 1981 because of reduced load growth, high interest rates and difficulty in attracting capital, said a Duke spokesman.

Duke says it will try and recover the costs through rate-increase requests.

Shortly after the cancellation decision, the North Carolina Utilities Commission granted the utility a $61.7 million rate increase. Last March, they had requested a $165.3 million increase.

Work continues on unit 1

According to Mary Cartwright, Duke spokesperson, work is continuing on Cherokee-1 at an "extremely slow pace." The company has spent $505 million on the 18 percent complete reactor. Only 140 workers are left at the construction site. In January 1981, about 1,800 workers were employed at the plant near Gaffney, South Carolina.

The utility said it will decide next year whether to go ahead with construction on Unit 1.

The three Cherokee units were part of a six reactor construction project initially designed to provide power for 1.3 million customers in the Carolinas. The other three reactors were cancelled last February.

Marble Hill rates to rise 85%, consultant calculates

NEW YORK, N.Y.—Aggregate electricity rates for all classes of Public Service Indiana customers will rise 85 percent over the period when the two Marble Hill nuclear units become operational, a utility analyst here has estimated.

This finding of Dr. Lewis Perl of the National Economic Research Associates, Inc. (NERA) has confirmed that this nuclear plant is one of the foremost candidates to experience the recently acknowledged phenomenon of "rate shock." One other nuclear plant that will experience this effect in a severe way is the Wolf Creek plant, being constructed jointly by Kansas City Power & Light and Kansas Gas & Electric (see *EL&P*, September 1982, page 3).

Both plants are being constructed in regulatory jurisdictions where prohibitions exist against collecting construction cost carrying charges from ratepayers during the building period, deferring such recovery until the plants are "used and useful." Such prohibitions against construction work in progress (CWIP) in rate base, which are in effect in only a minority of states, defer recovery costs until the plant becomes operational and then hit the ratepayer all at once.

Commissioned by the Indiana Public Service Commission to determine whether there was economic justification to continue construction of the Marble Hill plant, NERA's Dr. Perl concluded that there was such justification, provided construction cost escalations were not allowed to exceed more than 40 percent of the current $5.1 billion completion figure.

In accordance with this finding, Dr. Perl proposed that the PSC conduct an independent audit to determine if it was likely that the plant could be brought on-line for $5.1 billion. This proposal suggests the possible confluence of two recent regulatory developments in the Marble Hill case: rate shock and incentive rates of return (IROR).

If the commission decides that the plant can be completed for $5.1 billion, it may decide to implement somewhat stricter sanctions on utility management to assure that the cost target is achieved. By imposing an IROR, Public Service Company of Indiana shareholders would then be subject to a penalty if the target cost is exceeded. Indeed, in October, NERA proposed that the Indiana PSC think about a reward/penalty rate scheme for Marble Hill, and the commission currently is considering the idea.

The two-unit plant is being constructed by Public Service Company of Indiana, with a 17 percent ownership by the Wabash Valley Power Association, a group of rural electric cooperatives in nothern Indiana. Unit one is slightly over 40 percent complete, and unit 2 is nearing 30 percent. Startup dates are currently 1987 and 1988, respectively.

Interest is half of plant costs

Because the Marble Hill nuclear plant is being constructed in a jurisdiction that does not allow CWIP in rate base, about 45 percent of the total cost of the plant will be interest charges, James H. Pennington, vice president of financial operations at Public Service Company of Indiana told *EL&P*.

Exacerbating the company's financing situation is the fact it will have to go to the securities market for the rest of the money it needs to complete the plant. "We are at a point where we now are generating very little cash internally to finance construction," Pennington said.

Last August, Standard & Poor's lowered the company's securities ratings to BBB+, thereby signaling to potential investors that these securities were more risky and would require additional premiums.

Two major efforts are currently underway to relieve the company's rate shock problem. First, PSI says that it is mounting a vigorous effort in the state legislature to secure enabling legislation for CWIP in rate base. Although the Indiana PSC appears not

Continued on page 14

Foreign Power Briefs

- **Soviet officials** and representatives of two American companies—Bechtel Corp. and Occidental Petroleum are discussing possible plans for the construction of a coal slurry pipeline from Moscow to Siberia. Occidental Chairman Armand Hammer recently divulged the discussions in Moscow. Hammer said the Italian firm of ENI also may be involved with Bechtel and Occidental in the project. The pipeline would transport a coal/methanol mixture. Strong opposition from the U.S. administration is expected.

- **West German** demonstrators hurled tear gas, stones and gasoline bombs at police outside of Salzgitter late in October. They were protesting against construction of a nuclear-waste storage plant there. Authorities said 25 policeman were injured and at least 25 protesters arrested when 800 masked and helmeted demonstrators attacked police. Fighting erupted after nearly 6,000 environmentalists marched peacefully to protest the building of the facility.

- **Ontario Hydro** inked a 5-year, $8.1 million (Canadian) a year contract with Vermont for the sale of 52,000-kW. The contract allows for additional purchases of up to 252,000-kW. Ontario Hydro said that Vermont has been a customer for the past three years, ordering electricity on a weekly basis.

- **Japanese researchers** at Ehime University say they have discovered a simple solution to the problem of PCB disposal. An activated mass of charcoal is held at 600° C while the PCBs are filtered through it at a low pressure. Japanese scientists say the resulting products of the reaction are hydrogen chloride, biphenyl and alkylbenzene, all in gaseous form with no residue.

- **Bangladesh** wants a medium-sized power reactor. Air Vice-Marshal Sultan Mahmud, minister for energy and mineral resources, told attendees of the International Conference on Nuclear Power Experience in Vienna that the International Atomic Energy Agency should sponsor a reactor in a developing country. The minister offered a site in Bangladesh, saying that it had already been selected and cleared for construction. He said the IAEA would not be entering the commercial side of nuclear power, but would be working as a catalyst to demonstrate to others the viability of such a project.

- **The United Kingdom** will soon be getting use of a wind turbine generator in the country. The UK Department of Energy and the North of Scotland Hydro-Electric Board have signed contracts to erect a 3 MW, 60m blade diameter wind turbine on Orkney with completion in 1985.

- **The National Atomic Energy Agency of Indonesia** (BATAN) awarded a $22.7 million contract to General Atomic of San Diego for the design and equipping of a special facility for separating radioisotopes from targets irradiated in BATAN's new 30 MW research reactor. The isotopes will be prepared for use in industrial and agricultural research applications.

Work continues on the single unit 974 MW Confrentes Nuclear Power Station in the province of Valencia, Spain. Located on the Jucar River, the plant is scheduled to load fuel in late 1983 with commercial operation to begin in 1984. Gibbs & Hill, Inc. and its Spanish associate, Empresarios Agrupados, are supplying engineering and design services under a contract from Hidroelectrica Espanola, S.A..

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Recession causes wage freezes, employment cuts

Don Minner
Assistant Editor

BARRINGTON, IL—Facing a picture of declining profits and a sharp drop in energy and peak demand, two Ohio-based utilities have resorted to drastic cost-cutting measures.

Dayton Power & Light company slashed its employee ranks by 600 in October.

And American Electric Power System has instituted a massive cost-reduction program, which includes a general wage and salary freeze for 1983.

AEP also announced that it officially will close its New York office by Sept. 30 of next year, endangering many of the 900 employees' jobs.

An economic decline in DP&L's service area, along with a projected lack of any new customers forced the utility to drop employees, according to Chairman Robert Frazer.

About 300 employees took advantage of a one-time voluntary early retirement program.

Company spokesman Richard Martin said, "Another 300 jobs were eliminated throughout the company after a careful review of all positions and anticipated requirements."

Among the 300 were 240 union-eligible and 60 exempt employees.

Martin said no further cuts are expected.

The utility's projections indicate that less than 2,000 new customers will be added this year.

W.S. White, Jr., chairman of the board and chief executive officer for AEP, blamed reduced earnings levels on the drop in industrial sales and sales to other utilities. For the quarter ending Sept. 30 of this year, earnings per share dropped from $.55 in 1981 to $.33. Total energy sales are off 6.8 percent. Peak demand fell 7 percent in 1982 from 20,762 MW in 1981 to 19,301 MW.

"Should our circumstances deteriorate further, even more difficult steps may have to be taken," said White.

All top 140 officers and managers have taken a 5 percent pay cut and there will be no salary increases after Jan. 1.

Other elements of the program are:

—Reduction of employment through attrition, sharp restrictions on promotions and termination of temporary personnel.

—Curtailment of travel, training programs and reductions in contributions and memberships.

—Inventories reduced by 10 percent in dollars from Oct. 31 levels.

—Reevaluation of all construction programs, including an economic study of the construction schedule for Unit Two of the Rockport, Ind. plant.

—Suspension of all fuel supply projects and reduction of fuel stocks.

—Idling of Meigs 1 and 2 coal mines in southern Ohio.

—Cutback in advertising, overtime and outside services.

White blamed the New York closing on the bleak economic picture and a revised AEP load forecast of less than 3 percent for the balance of the decade.

Some of the 900 employees there will be asked to move to Columbus, but the company says it doesn't know how many will be affected by the closure next September.

A $15 million feasibility study for a pumped storage hydroelectric project in southwestern Virginia was also cancelled.

Appalachian Power Company President John W. Vaughn said the utility has filed a request with the Federal Energy Regulatory Commission to withdraw its preliminary permit to conduct the studies. The utility is a subsidiary of AEP.

On a more positive note, the utility announced that it signed two long-term contracts for power sales to other utilities.

One contract calls for AEP to sell to Allegheny Power System 560 MW, continuing through 1990.

The other is a two-year contract with Virginia Electric and Power Company for 600 MW.

A random check of other utilities throughout Illinois, Michigan, Ohio and Pennsylvania—areas hit hardest by the recession—found that most utilities have instituted hiring freezes.

Midmark moves

VERSAILLES, OH—Midmark Corp., formerly of Minster, Ohio, has moved into its new facilities here. Midmark used to be known as IE Industries. The company manufactures trenchers and a variety of other industrial products.

NERC expects power reliability problems

PRINCETON, N.J.—The North American Electric Reliability Council, assuming a 30 percent reserve margin in 1991, has cast doubt on the adequacy and reliability of power supply capabilities over the next decade.

Noting that demand is tied to economic growth more than to any other single element, NERC declared in its 12th annual review of U.S. bulk power systems that with "the completion of only those generating units presently under construction, the utilities of the nation would be able to support in a reliable manner a peak load increase of only about 86,000 MW during the 1982-1991 forecast period, rather than the 131,000 MW increase now being projected by utilities. This 45,000 MW reduction in supportable load growth would have a negative impact on the future economic activity of the nation."

This rather severe conclusion, which some would find arguable, is based on NERC's perceived necessity to hold fast to a national reserve margin of 30 percent. According to a NERC spokesman, the shortfall calculation, with its attendent "negative impact," was based on a 30 percent reserve margin because this is what the national reserve margin would be if all the generating units electric utilities want to build are, in fact, built. "The implicit assumption here," the spokesman said, "is that companies are not planning to build what they don't need."

It is important to bear in mind when reading NERC forecasts that they are constituted by aggregating existing forecasts calculated by electric utilities; each of the nine NERC regions collects utility forecasts for its area and NERC then aggregates the regional contributions. Because of this, regional differences can be substantial.

NERC believes that although sufficient reserves have been planned by U.S. electric companies during the next 10 years to reliably meet anticipated demand, financial and possibly other obstacles could work to keep these plans from being realized

The U.S. summer peak demand has been forecast by NERC as 438,000 MW in 1982 (see Table A), and is expected to increase to 569,000 MW by 1991, an increase of 131,000 MW. To meet this expected demand, U.S. electric utilities are planning additional generation plants of about 157,000 MW, bringing total installed capacity to 738,000 MW (Table B). On this basis, NERC says, generating capacity reserves in 1991 are planned to be about 169,000 MW, or about 30 percent.

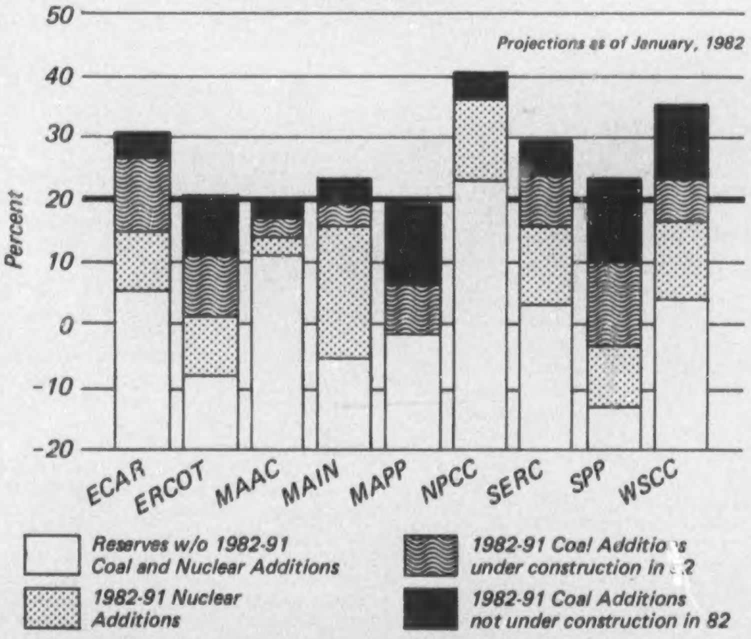
TABLE A
PEAK DEMAND AND ENERGY

	NERC (U.S.)			NERC (Total)		
	1982		1991	1982		1991
Summer peak (thousands of MW)	438		569	478		630
Average annual growth (%/yr)		3.0			3.1	
Winter peak (thousands of MW)	404		531	460		617
Average annual growth (%/yr)		3.1			3.3	
Net energy for load (billions of kWh)	2,385		3,181	2,696		3,367
Average annual growth (%/yr)		3.3			3.5	

TABLE B
INSTALLED GENERATING CAPABILITY

	NERC (U.S.)			NERC (Total)		
	1982		1991	1982		1991
Summer (thousands of MW)	582		738	649		836
Average annual growth (%/yr)		2.7			2.8	
Winter (thousands of MW)	599		748	667		849
Average annual growth (%/yr)		2.5			2.7	

TABLE C
1991 NERC (U.S.)
REGIONAL RESERVE MARGINS (%)
(SUMMER)



But the council's recent electricity forecast hastens to point out that "It must be recognized that planned future reserves are dependent on about 50,000 MW of generating capacity which is not yet under construction. Should the current financial constraints facing many utilities continue, there is no assurance that all of this capacity will be constructed."

The council calculates that if the coal plant additions that are planned by utilities for the 1982-1991 period, but have not yet begun construction, do not materialize, four of the nine NERC regions will have regional reserve margins below 20 percent (see Table C). These four regions are the Electric Reliability Council of Texas (ERCOT), the Mid-Atlantic Area Council (MAAC), the Mid-Continent Area Power Pool (MAPP), and the Southwest Power Pool.

NERC worries further that the completion of all the generating units presently under construction is not at all a sure thing. "The financial and regulatory uncertainty associated with many new generating projects leads to the possibility that some of this capacity may yet be cancelled or indefinitely deferred," the council's forecast report reads. "Should this occur, reserve levels for 1991 would be further reduced, further jeopardizing reliability."

BPA looking for 1.6% annual growth

PORTLAND, OR—After three months review of a draft forecast published in April, the Bonneville Power Administration has again revised its long-term load forecast for the Pacific Northwest.

"Overall, our responses to the many comments we received added up to only a slight change in the expected annual growth rate over the next two decades," BPA Administrator Peter T. Johnson said. "We are now predicting a compounded growth rate of 1.6 percent annually until the year 2000 compared to the 1.7 percent rate spelled out in our draft forecast.

"Load growth in the 1980's, however, is now expected to be slightly higher than predicted in April. The forecast assumes a marked recovery from the present recession."

Slight changes

The final forecast also brought about slight changes in the high and low load growth cases. The high-case 20-year growth rate was reassessed downward from 2.5 to 2.4 percent annually, and the low-case rate upward from 0.8 to 0.9 percent per year.

Telelect Inc. adds on

MINNEAPOLIS—Telelect Inc. recently broke ground for a new facility at their Watertown, South Dakota operation.

A company official said the new building will consolidate the firm's sales, engineering and administrative functions to one location. It is expected to be completed in the spring of 1983.

Senior top utility executive salaries rank low in overall comparison among 27 industry groups

NEW YORK—Salary levels of senior top utility executives ranked 23rd among 27 industry groups compared in a recent study.

Average total compensation for utility senior executives was $111,657, which represents an 11 percent average earnings increase.

Arthur Young says that the 11 percent rate of annual increase for all senior executives marks a decline from the utility industry's average advance of 16 percent in 1980. It is also substantially lower than the 13 percent average increase registered by executives in other major industries in 1981.

The study, conducted by Arthur Young & Company for the Financial Executives Institute, also showed the utility industry ranked tenth in the average annual rate of gain in top executive pay.

Chief executive officers of utilities of all sizes were paid an average of $230,456, an increase of 13 percent.

Other utility salaries

Average 1981 earnings for other top executives in the industry, with increases in total compensation shown in parentheses, were: chief operating officer, $158,868 (13%); top financial officer, $116,002 (12%); top marketing executive, $76,615 (10%); and top human resources executive, $69,854 (9%).

Highest paid top U.S. executives were those in the chemicals industry, earning an average total compensation of approximately $190,319. They were followed by top executives in the petroleum industry who earned, on average, $172,550, and those in communications, with average earnings of $166,874.

Lowest paid execs

The study found that executives in the real estate industry ranked lowest among the 27 industries, earning an average of $96,437, following closely the average pay of $101,012 to top executives in the commercial banking industry and the average of $103,843 to those in life insurance.

Study based on

The study was based on the pay of approximately 16,500 top executives of more than 1,600 companies in 27 industry groups, and in all seven regions of the country.

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Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

Congress passes nuclear waste legislation

Don Minner
Assistant Editor

WASHINGTON, D.C.—Nuclear waste will finally get a home.

After more than 25 years of debate, Congress passed and President Reagan signed nuclear waste legislation that has been called "landmark" by lawmakers.

The compromise bill, H.R. 3809, was passed 256-32 in the waning hours of the lame duck session of Congress after co-sponsers of the House bill James Broyhill (R.-NC) and Mo Udall (D.-AZ) did some political maneuvering to get the bill on the floor.

Earlier the Senate had passed it by a voice vote.

The bill sets a timetable to establish a permanent geologic repository by the mid-1990s, and strengthens states' rights of participation in the selection of interim burial sites and allows states to reject their selection for a permanent storage site, subject only to an override by both Houses of Congress.

The legislation also will make it easier for utilities to expand their present spent fuel storage pools and it provides for interim storage at existing federal facilities for utilities who are facing a plant shutdown because they are approaching the limits of on-site storage.

Praise for bill

Energy Secretary Donald Hodel praised passage of the bill, saying, "It provides long overdue assurance that a safe and effective solution to the nuclear waste problem is in hand. This is landmark legislation."

Within one year after enactment of the bill, the Department of Energy is required to identify three or more sites in two geographic areas for a Test and Evaluation facility for demonstration of the technology for disposal of high level waste. DOE then would begin a testing program at one or more of the sites 76 months later.

DOE must pick five potential sites for a permanent-full scale repository by Jan 1, 1985 and the President must select one of them by March 31, 1987. The Nuclear Regulatory Commission then has until the end of Jan. 1989 to decide whether to license the site.

DOE would nominate another five sites by July 1, 1989 from which the President is to pick a second location by March 31, 1990.

The final repository would be in stable geologic formations 2,000 to 3,000 ft underground that would be able to prevent a radioactive release for 10,000 years.

States have veto power

States will be able to veto their selection as the permanent repository site, unless overridden by majorities of both the House and the Senate.

The original bill in Congress only required one house of Congress to overrule a state's objection. But the final language was agreed upon in a last minute compromise.

DOE said that two sites have been chosen for further study: a basalt rock formation in Washington and a volcanic tuff formation in Nevada. Other sites under study are located in Mississippi, Utah, Texas and Louisiana.

Spent fuel storage provided

The legislation provides for two types of interim surface storage facilities to hold spent fuel until a federal repository is ready for it.

Spent nuclear fuel assemblies are shown here being transported to a test site in Nevada. President Reagan recently signed "landmark" legislation that sets a timetable for establishing a permanent geologic repository by the mid-1990's.

If a utility is running out of on-site space, the bill allows the government to provide temporary storage for a limited amount of spent fuel (up to 1,900 metric tons) at existing federal facilities. Prime candidates are located at military installations in Nevada, Washington and South Carolina.

Additionally, the legislation calls for DOE to recommend to Congress before June 1985 three to five sites for a "monitored, retrievable storage" facility, where spent fuel could be stored until a decision is made whether to send it to a nuclear-fuel

Continued on page 2

DOE, utilities seek alternative funding for Clinch River

Dan Utroska
Associate Editor

WASHINGTON, D.C.—While approving continued funding for the experimental Clinch River breeder reactor for fiscal year 1983, Congressional conferees last year mandated one important proviso: the Department of Energy, in cooperation with the nuclear industry, is to investigate alternative means for financing the demonstration reactor plant.

Last December, a House and Senate conference committee agreed to appropriate $188 million for the rest of the year, but there is a definite belief on the part of some congressmen that the federal government, in a time of fiscal austerity, is simply putting up too great a share for Clinch River.

As it now stands, electric utilities have pledged $257 million—a figure offered when Congress first authorized Clinch River back in 1972 and the entire project was estimated to cost just $699 million. With interest the industry figure will grow to $340 million. But compared to that portion of the costs that will be borne by taxpayers, the industry's share has decreased sharply and now falls between 4 and 8 percent of total costs, depending on what estimate is used. The Department of Energy estimates that the total project will cost $3.6 billion, but the General Accounting Office has set the figure over $8 billion.

The House of Representatives last year voted 217 to 196 to eliminate all funding for Clinch River, but that body yielded its collective view in conference committee. Many House members are said to be in favor of continued government participation in the project only if some sort of "cost-share" policy is adopted.

According to one House energy aide, with the preponderance of fund-

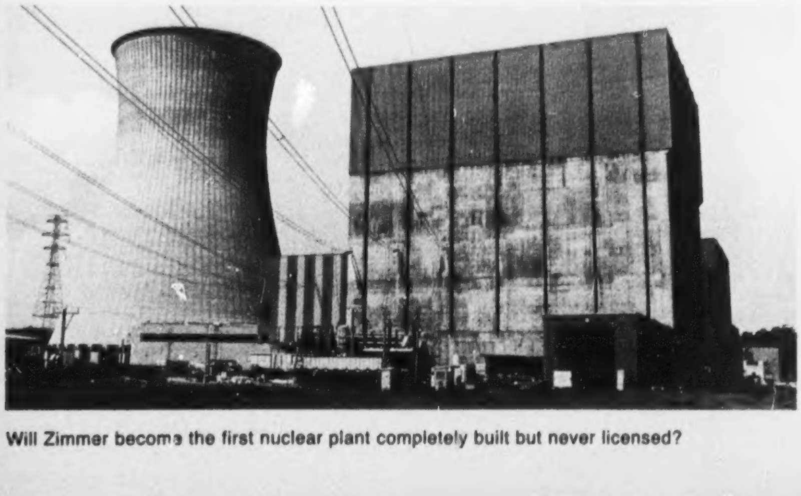
Continued on page 2

CG&E eyes Bechtel to solve construction deficiencies at Zimmer nuclear plant

Stop-work order continues

CINCINNATI—Cincinnati Gas & Electric has appealed formally to the Nuclear Regulatory Commission to let it employ the Bechtel Power Corporation to conduct a third party audit of its nearly completed Zimmer nuclear plant. By its action, the utility hopes to extricate itself from a morass of construction difficulties that some say could result in Zimmer becoming the first nuclear plant ever to be completely built but not licensed.

As the result of accumulating construction and quality assurance deficiencies over the past several years, combined with pressures from some consumer groups, the Nuclear Regulatory Commission last November 12 issued a stop-work order on the 98-percent-complete plant, pending an "independent review" of the licensee's management of Zimmer construction activities.



Will Zimmer become the first nuclear plant completely built but never licensed?

In its November 12 order, the NRC detailed a host of deficiencies, dating back to 1981. Referring to an agency investigation conducted early that year, the NRC said it had "revealed a widespread breakdown in CG&E's management of the Zimmer project as evidenced by numerous examples of non-compliance with 12 of the 18 quality assurance criteria" of NRC regulations.

The commission recalled that CG&E paid a civil penalty of $200,000 for "the failure to implement an acceptable quality assurance program, false quality assurance documents, and intimidation and harassment of quality control inspectors."

In addition, the utility reportedly

Continued on page 3

Foreign Power Briefs

- **South Africa's first nuclear plant** was sabotaged by an outlawed black guerrilla group. Four explosions shook the Koeberg power station, north of Capetown. Police said damage to the nonoperational reactor was limited to cable installations and other equipment. The guerillas said the attack was in response to a South African commando raid on its members in a neighboring town. According to police, there was no radioactive material in the site.

- **Israel** was paid a visit in December by Dr. Edward Teller. He was there to advise the government on building a nuclear reactor for peaceful purposes, according to a Ministry of Science spokesman.

- **Malaysia's** oldest electric company, the 55-year old Perak River Hydro Electric Power and a subsidiary, Kinta Electrical Distributors, have shut down. The National Electricity Board has taken over their responsibilities. The government is reorganizing so that there will be a single public electricity supply authority for the Malaysian peninsula.

- **A Swiss Senate** special commission has voted to support construction of the country's sixth nuclear plant. A vote by the full Senate and House is still necessary before any work can begin.

- **Tohoku Electric Power Co., Ltd.,** of Japan placed an order with Mitsubishi Heavy Industries, Ltd. (MHI) for delivery of a combined cycle power generation facility with a total capacity of over 1 million kilowatts for unit 3 at its East Niigata power plant. MHI will manufacture the facility, the first of its kind in Japan, using Westinghouse technology for both the combustion turbine and combined cycle power plants. The unit is scheduled to start-up in 1984.

- **The Republic of Korea's** 600-MW Wolsung Candu reactor started up in November, five years after construction had begun.

- **The Matimba Power Station** in South Africa will be a pioneering step for dry-cooled power plant design. Engineering on the plant has begun and fabrication will soon start in order to meet the 1986 start-up of the first of six 665-MW units. The size of the overall project and also the unit size makes it twice the capacity of the world's largest operating air-cooled condenser at the Wyodak Station in Wyoming.

- **Pakistan's** 937-MW Chashma nuclear plant is almost ready for construction to start. Site preparation has been completed and work is to begin in the later part of the year.

- **An Atomic Energy of Canada** study shows that construction schedule changes are a prime reason for capital cost escalation for Candu nuclear plants. The report concludes that Candu plant costs, exclusive of heavy water, interest, schedule deferment and boiler repairs, show a rise of approximately one percent a year.

- **One of Holland's** two nuclear plants was evacuated after a water leak was discovered recently. Officials at the 450-MW unit in Borssele said 1000 cubic ft of "slightly radioactive" water escaped from the primary cooling system before being disovered. The plant had already been shut down for repairs before the leak occurred.

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The conversion of utility oil- and gas-fired capacity to coal burning has entered a second phase: conversion of plants originally designed to burn oil or gas. G 24

1983 should be the year of decision for EPA rules governing disposal of air pollution wastes. Disposal costs could run as high as $3 billion. G 34

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EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (••). All readers receive EL&P's industry news section.

Floating TVA exhibit celebrates 50 years

The Valley Adventure, a colorful floating exhibit which hosted more than 1.1 million visitors during the 1982 World's Fair, will travel to 23 communities in the Tennessee Valley during 1983 to celebrate TVA's 50th anniversary. The exhibit features a variety of animated displays and will be open free of charge at each stop.

CRBR . . . From page 1

ing coming from taxpayers, the initiative to keep the project alive appears to rest with Congress, rather than with the utility industry. In its early vote to eliminate funding for this experimental breeder, the House had in mind a switch in initiative, transferring the momentum for the project to the industry. It is believed that after securing increased funding, the industry would find Congress more inclined to provide supplemental appropriations, the aide said.

Even though this idea was effectively obviated by the House/Senate conference vote to restore funding for FY '83, the underlying spirit still appears to be alive, as evidenced by the conferees' decision to put a specific provision in the continuing resolution allocating $1 million for an examination of alternative financing methods.

Counterpoised to the congressional notion that the industry ought to explore ways to increase its share of the project is the industry's position that it should not be stuck with the tab for congressional and administration dallying. "Most of the cost overruns are directly attributable to the previous administration," Wallance Benke said, referring to the Carter Administration's effort to scrap Clinch River. Benke, who is board chairman of the Project Management Corporation, noted that Congress did not authorize enough money to keep the project on schedule the past few years.

At press time, the utility industry, in response to a DOE request, had set up a task force aimed at seeking increased private financing for CRBR. Benke declined to name members of the "informal" group, saying that the complexion of the group would change over time and "when they get some work done they will be prepared to talk."

Is it likely that private industry will contribute more funds than they agreed to when the project was first authorized, Benke was asked.

"To attempt to pry that open at this point is a very complicated matter," he said. He noted that it was "problematical" whether electric companies would be successful in going back to ratepayers to ask for more funds for the project when the schedule delays and cost overruns are the fault of the government. "This is a government research and development project, pure and simple," Benke responded.

The Department of Energy reportedly will be working closely with the industry, and the agency is required to report to Congress by March 15 on the industry's and its own investigation into alternative funding.

Waste bill . . . From page 1

reprocessing plant or to a geologic repository.

Rep. Broyhill said, "...our electric utilities will be assured if they run out of storage space for their spent nuclear fuel, they will not have to shut down their power plants for lack of storage space. The taxpayers won't pay a dime—the whole program will be financed up-front by private user fees that will reduce the Federal budget deficit by an estimated $14 billion between now and the end of the 1990's."

Utilities charged user fee

The user fee would be based on a one-mill per-kilowatthour charge on nuclear generation for as long as is necessary to offset the costs of constructing the permanent disposal site. The charge could be added to customer's utility bills, if approved by state utility commissions.

DOE expects that the fee would start being collected in mid-1983. It hopes the fee will provide $300 million during the remainder of that fiscal year and $500 million in fiscal 1984.

The bill requires that military waste facilities be subject to the same state veto procedures, but exempted from the other procedures unless the President doesn't object to burial with civilian wastes.

Carl Walske, president of the Atomic Industrial Forum, praised all involved in achieving a timetable on waste disposal. He said it paves the way for future legislation.

The Senate had passed its proposal (S 1662) in April 1982, but the House version took six months to arrive. Seven committees constructed the House bill before the 1982 recess and sent it to the Senate. After much behind-the scenes negotiating, the bill finally was passed Dec. 20.

NRC tells court why early CRBR site work was justified

WASHINGTON, D.C.—Emphasizing that "time was of the essence" when it decided to grant an exemption to its regulations to authorize early site work for the Clinch River breeder reactor, the Nuclear Regulatory Commission has decided 3-2 to reaffirm its original conclusion.

The reaffirmation was conveyed in an agency memorandum and order which spelled out the reasons underlying the commission's earlier decision to permit site clearing work for the experimental breeder reactor without a full-fledged hearing on the matter. The detailed explantion was prepared in response to a ruling December 7, 1982, by the U.S. Court of Appeals for the District of Columbia Circuit. The court said the NRC must either conduct an adjudicatory hearing under its regulations to determine if CRBR site preparation activities should be allowed to continue, or identify the "exigent," or emergency circumstances that warranted the suspension of the required hearing process.

Commissioners Gilinsky and Ahearne dissented from the majority (Palladino, Roberts, Asselstine) decision to reaffirm the correctness of its exemption conclusion.

The court's ruling was the result of a claim, filed by the Natural Resources Defense Council and the Sierra Club. They claimed the NRC had violated its own rules when it authorized preliminary site work. NRDC had asked for a stay in construction activities at the site, but the court, while requiring that the NRC justify its preliminary CRBR site clearing decision, refused to stay current work there (*EL&P*, November, page 1).

Public interest calls for site work

In its response to the appeals court, the NRC said that to have delayed its decision to allow construction activities at the Clinch River site would have denied the public the benefits of prompt completion of the facility.

"The commission found that CRBR had reached such an advanced state of development that important anticipated benefits could now be realized only by prompt initiation of site preparation activities," the NRC argued in its memorandum to the appeals court.

The agency noted that at the time of its decision, more than $600 million of parts and hardware were either delivered or on order, and that the project design at that time was more than 90 percent complete. "Further progress on the projectr required the initiation of site preparation activities," the agency said.

Having been informed by the Tennessee Valley Authority and the Project Management Corporation, applicants to build Clinch River, that the liquid metal fast breeder reactor (LMFBR) base research and development program, as well as the large development plant and the LMFBR fuel cycle program had progressed to the stages where future progress could be delayed by any further CRBR postponement, the NRC concluded that it was in the public interest to grant the exemption allowing site preparation activities to begin.

The commission also determined that the public could lose its investment in the cadre of technically trained personnel who might otherwise drift away to other, more active, engineering projects.

In addition, the NRC said a further delay could result in incremental costs of $28 million per year arising from events that would not be present in its previously established construction schedule. "The mitigation of such adverse consequences of unforeseen delay is the very kind of relief an exemption is designed to provide," the NRC said.

Finally, the commission also found that delays in CRBR could jeopardize the establishment of cooperative agreements for developing LMFBR's in conjunction with the nuclear industry and potential foreign competitors.

Dissenters challenge NRC ruling

Criticizing the calculations showing that early site work would save the project $28 million a year, NRC commissioner Victor Gilinsky said this determination was erroneously based on an "artificially low 3 percent discount rate."

"The commission is fully aware," Gilinsky said, "that if a more realistic 10 percent discount rate (that recommended by the Office of Management and Budget for evaluating the economic effects of regulatory decisions) were used, the economic effect . . . turns out to be a loss of $42 million."

Concluded Gilinsky, "The real reason the commission is granting this exemption is, of course, the Department of Energy's desire to get work underway at the Clinch River site in order to forestall an adverse decision by Congress. However understandable DOE's motives may be, this does not qualify as an exigent circumstance justifying an exemption from our regulations."

Commissioner John F. Ahearne also dissented, noting that in reaffirming its decision to grant authorization to conduct early site work, the NRC had discarded its standard definition of "exigent circumstances."

Said Ahearne, "The straining in the current order strengthens my belief the exemption should have been denied."

SW Public Service: an atypical firm

CHICAGO—At a time when the news is filled with the financial and regulatory crises of electric utilities, Southwestern Public Service Company is sitting pretty.

"Southwestern Public Service is not your typical electric utility company," Berl M. Springer, chairman and chief executive officer recently told analysts at the Utility and Telecommunications Securities Club here. "We are different. We trade up on that difference every chance we get."

One way the company "trades up" is to hold off on a proposed stock issuance, waiting for the market price to nudge itself higher than the 140 percent of book value the company could have secured if it had gone to the market. "We decided not to sell at 140 percent of book," Springer said, referring to a proposed 1.4 million share sale. "We think that with falling interest rates, stock prices will actually increase."

For the 12 month period ending October 31, 1982, total operating revenues climbed to $615.8 million, a 14.5 percent increase over the same period the previous year. Disregarding fuel-related revenues that were passed through, the increase was 12.9 percent.

Net operating income grew by 21.9 percent over the same period.

Electricity use down 2 percent, says EEI

WASHINGTON, D.C.—National electricity output fell 2.2 percent in 1982, according to figures released by the Edison Electric Institute.

Electricity output is the quantity of energy used by consumers, and is measured in kilowatt-hours. It is to be distinguished from peak demand, which is the rate of energy use measured in kilowatts. Earlier, *EL&P* has reported that peak demand was also down 2 percent for the year (see October, 1982 issue, page 1).

As can be seen from the chart, the Central Industrial and the Pacific Northwest area suffered the largest losses in output, each being down 4.7 percent compared to one year ago. These losses are, in the main, traceable to the national economic recession.

The Central Industrial area includes the auto and steel industries, both of which have been hard-hit by reduced product demand. This translates into reduced electricity consumption. In the Pacific Northwest, where the aluminum and timber industries constitute major portions of the economic strength of that area, production also has fallen off. The timber industry is lagging due to a decline in the new building industry.

In addition, the Pacific Northwest seems to be sensitive to energy prices, according to a spokesman for the Bonneville Power Administration. "Consumers do respond to price-induced conservation," noted BPA's Ed Mosey. Because of the large hydro power base in the northwest, the cost of electricity has been moderated by the relatively inexpensive power produced by dams. When prices rise, as they have recently, customers respond by reducing demand, even though prices are still less than the national average, Mosey said.

All of the nine Edison Electric Institute geographical regions experienced electricity output declines in 1982, except the South Central region, which was unchanged, and the New England region, which experienced a growth in output of 0.4 percent.

WEEKLY ELECTRIC OUTPUT BY GEOGRAPHIC DIVISION
(48 Contiguous States)

	52 Weeks Ended December 25	
	Kilowatt-hour output (millions)	% Change over corresponding period of 1981
New England	84,872	+ 0.4
Mid-Atlantic	303,802	- 1.0
Central Industrial	459,747	- 4.7
West Central	157,708	- 0.1
Southeast	504,217	- 2.9
South Central	326,210	0.0
Rocky Mountain	108,550	- 0.4
Pacific Northwest	134,190	- 4.7
Pacific Southwest	183,305	- 1.7
Total United States	2,262,801	- 2.2

Source: Edison Electric Institute

Appointed PUCs rank higher in analyst ranking

NEW YORK—Public utility commissions that are appointed rank much higher than those that are elected, according to a Solomon Brothers ranking.

Grading was based on allowed return of equity and other financial considerations.

Of 49 commissions rated (including FERC but omitting PUCs in Nebraska and South Dakota), the 12 that got marks higher than C+ were appointed.

Out of eleven elected PUCs, six were graded D or E.

Appointed commissions in Indiana and Texas received the highest ranking of A. Of elected bodies, Arizona ranked highest with a C+ and commissions in Oklahoma, Virginia and South Carolina got a C marking.

Alabama (elected) and Missouri (appointed) PUCs were ranked at the bottom of the utility analyst's report.

Solomon Brothers said the regulatory climate nationwide has improved during the year. Although they said the long-term financial health of the industry is still in doubt.

THE NATION'S PUCs
RATED BY SALOMON BROTHERS

A	Indiana, Texas
A–	Utah
B+	Florida
B	North Carolina, Wisconsin
B–	California, Hawaii, Kentucky, New York, New Mexico, Ohio
C+	**Arizona**, Colorado, Connecticut, Delaware, FERC, Illinois, Nevada, New Jersey, Oregon, Vermont, Washington
C	Arkansas, Kansas, Maryland, Massachusetts, Minnesota, New Hampshire, **Oklahoma**, **South Carolina**, **Virginia**, Wyoming
C–	Idaho, Iowa, Maine, **Louisiana**, Michigan, Pennsylvania
D	District of Columbia, **Georgia**, **Mississippi**, **Montana**, **North Dakota**, Rhode Island, **South Dakota**, **West Virginia**
E	**Alabama**, Missouri

Bold listings denote PUCs whose members are elected.
Light listings denote PUCs whose members are appointed.

BEST AVAILABLE COPY

Chemically fixed sludge can be handled at the dry landfill via truck, as shown at this Conversion Systems installation at Columbus & Southern Ohio's Conesville station.

Utilities ponder $3 billion annual price tag for scrubber sludge disposal

The tension is building as the utility industry awaits the decision, due this year, from EPA on whether or not coal-combustion waste products are hazardous, as defined by the Resource Conservation and Recovery Act (RCRA). Scrubber sludge and fly ash disposal costs could be doubled or even tripled to more than $3 billion a year pending the outcome, reported EPRI's Dean Golden, at the Coal Technology conference in Houston last December.

The big question, Golden told attendees, is, will you need a liner for the disposal site? EPA has made it clear in previous rulings that it will not accept clay linings for hazardous waste sites, he added. The agency wants synthetic membrane liners which will boost coal plant waste disposal costs as much as $35 a ton. Utilities currently spend less than $1 billion a year on waste disposal. If EPA rules that the wastes should be classified as hazardous and requires liners at all sites, the cost would be $3.4 billion a year.

Utility combustion wastes are currently exempt from the law while an EPA-sponsored study of their environmental effects is being done by Arthur D. Little, Inc. The study is almost done and the EPA ruling is expected six months later. Continued total exemption from the RCRA rules is "not in the cards," says Golden. He expects a ruling somewhere in between the two extremes. If a special non-hazardous class were set up for utility sludge and fly ash requiring, for example, liners for half the sites, the annual cost would be in the range of $1.9 billion to $2.6 billion, said the EPRI official, which is still substantially more than current regulations require.

FGD SLUDGE DISPOSAL PRACTICE—OPERATIONAL, UNDER CONSTRUCTION OR COMMITTED (BASED ON NUMBER OF SCRUBBING UNITS SERVED)

	Scrubbers served
Wet Ponding	
Direct ponding	28
Dewatering	30
Fixation	4
	62
Dry Landfill	
Dewatering	27
Blending with flyash	17
Fixation	43
	87
TOTAL	149

Source: "Flue Gas Desulfurization Sludge Disposal Technology, State-of-the-Art 1982," by Charles Smith, Coal Technology '82.

The amount of utility waste produced in 1979, the last year for which full data are available, was 79.5 million tons, Golden reported. That includes 18 million tons of bottom ash and slag, 57.5 million tons of fly ash, and 4 million tons of FGD dry solids. Golden pointed out that the FGD total is rising rapidly, though. He predicted that by 1987 30 million tons of FGD sludge will be produced, six times the 1980 total. That's because there are nearly 130 coal-fired generating stations under construction or planned that will have sulfur dioxide control systems.

Wet sludge

Another speaker at the Coal Technology conference, Charles Smith, principal researcher for Conversion Systems, Inc., a major supplier of disposal services, explained that most FGD waste is produced in the form of wet sludge, 5 to 12 percent solids. Of the 160 FGD systems in operation, under construction, or committed, said Smith, most will produce this aqueous sludge, which poses a difficult disposal problem.

Sludge disposal generally falls into two categories, as shown in the table which is taken from Smith's paper. (It covers all but the 11 regenerative type scrubbers which produce no waste.) The wet pond method is popular in the west where arid conditions are conducive to evaporation. In the east however, the rainfall rate exceeds the evaporation rate, so the low-solids sludge has to be disposed in some sort of "dry" form. As shown in the table, simple dewatering (to the 40 to 60 percent solids range) is used for 27 of the 87 dry landfill cases. At 17 of the units the scrubber sludge is physically "stabilized" by blending it with flyash.

The remaining category, the largest, is chemical fixation which involves adding lime and other reagents to the sludge so that it sets up to a soil-like consistency. Smith reported that his firm dominates the market for chemical fixation installations with 22 operating systems and 16 more under construction or committed out of the total of 42. The remaining suppliers, Smith reported, are Burns & McDonnell and Babcock & Wilcox with one operating system each, Peabody Process Systems with one commitment, and GE Environmental Services with two commitments. In the wet pond category, Dravo has four operating chemical fixation systems.

A query from the audience on forced oxidation yielded a difference of opinion between the two speakers. Smith had reported that it was possible to oxidize many sludges to calcium sulfate—gypsum—which could be dewatered to 80 percent solids. Asked if that might not become a favored route for utilities since there might be a commercial market for the gypsum, Smith said that there has been little success in this country selling sludge gypsum, which is necessary to make forced oxidation economical. He said that the product is unsuitable for wallboard because the color is bad and the material has a high chlorides content. Smith doubted that sludge could be disposed in the form of gypsum because its high solubility, he said, "has caused EPA concern." Gypsum stacking is acceptable "for the moment," he said, claiming that its future is questionable.

EPRI's Golden disagreed about the marketability of sludge gypsum. He said the material is suitable for wallboard, that color doesn't matter because it's covered with paint, and chlorides are not really a problem. Golden said that many wallboard manufacturers are now importing gypsum and that a domestic source would be welcomed. He added that Tampa Electric is going to forced oxidation at the scrubber installation at its Big Bend station and intends to sell the gypsum to a local wallboard manufacturer.

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Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

Defense gets big slice of energy budget

WASHINGTON, D.C.—Over half of the Department of Energy's 1984 $11.9 billion budget request has been targeted for defense activities.

Approximately $6.8 billion has been earmarked to fulfill Department of Defense requirements for nuclear weapons and materials production, a $1.1 billion increase over 1983's estimate.

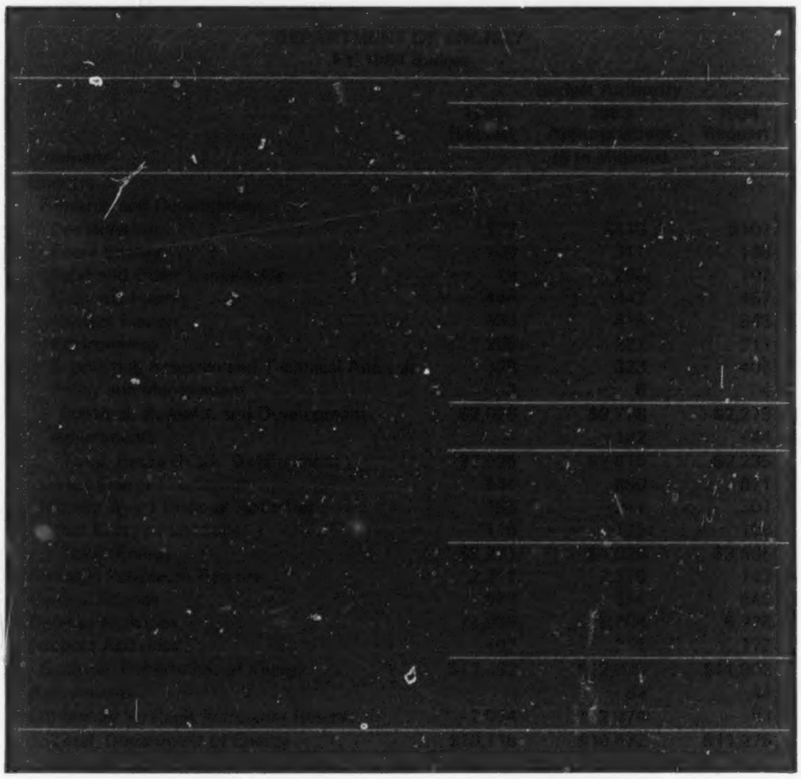
The overall budget reflects a seven percent drop from 1983 funding estimates. It includes a $3.5 billion allocation for energy programs, $742 million for the Strategic Petroleum Reserve, $645 million for general science programs and $172 million for support activities.

DOE notes in its budget that re- reflect the Administrations intent to eliminate the department and reassign its activities.

Energy funds down

Funds for energy programs were cut $408 million from 1983. DOE requested $2.3 billion for R&D activities in 1984, as compared to 1983's $2.8 billion request. R&D budget requests were up for magnetic fusion, nuclear fission and supporting research and technical analysis, but requests for fossil energy, conservation, solar and other renewable funds were down.

Monies for renewable energy programs were slashed more than half to $102 million from 1983's $252.6 million estimate. No funds were requested for solar programs (except photovoltaics), ocean energy systems development and hydropower programs.



DOE says that the technology base for active and passive solar activities is already well-established. It added that the technical feasibility of Ocean Thermal Energy Conversion has been proven.

Photovoltaic programs were chopped to $32.7 million from $58 million; wind activities are budgeted for $8.6 million, a $22.8 million reduction from 1983 requests; and geothermal funding estimates for 1984 are $13.6 million, compared to 1983's $49.6 million request.

Also in the energy program budget is a $306.7 million request for the nuclear waste fund. It will be used to finance activities related to the development, construction and operation of a commercial high-level waste repository. The fund will also be partially financed by fees paid by nuclear utilities.

Petroleum reserve sound

DOE is asking for a $1.6 billion reduction in funding for the Strategic Petroleum Reserve in 1984. The $741.9 million request reflects the significant improvement in the country's protection level, says the department. It expects that 410 million barrels of oil will be in storage by the end of fiscal year 1984, with 18 million more on the way in 1985.

All three programs under the general science category are asking for increased funding in 1984. The high energy physics, nuclear physics and program direction activiites are programs administered as national trusts to advance knowledge on the frontiers of science.

Continued on page 3

LILCo seeks rate phase-in for Shoreham nuke

ALBANY, NEW YORK—In an attempt to insulate its ratepayers from the shock of a large rate hike when the Shoreham nuclear plant becomes operational, Long Island Lighting Company has submitted a rate phase-in plan to the New York Public Utility Commission.

Rate shock is a relatively new phenomenon in the electric utility industry and has been found to strike those companies that are completing new power plants which, under conventional ratemaking procedures, threaten to hit electricity consumers with extraordinarily large rate increases when the plants become operational.

Lilco has been at the leading edge of this new concern, and in recent company testimony Lilco confirms previous calculations that without some form of innovative rate base treatment, the price of electricity during the first year of Shoreham nuclear plant operation will be 43 percent higher than the year before. Thirty-eight percent of this is directly attributable to Shoreham, the company has said.

In evidentiary hearings before the New York Public Service Commission, Lilco outlined the details of its "rate moderation plan" (RMP). "We believe that the RMP . . . will moderate the rate increases to levels that most satisfactorily balance the immediate interest of the consumers who are anxious to keep to a minimum short-term increases in the cost of any commodity which they purchase, and the interest of the investors who

Continued on page 3

Consumer study sets the stage for new federal role in the planning of new power plants

WASHINGTON, D.C.—The results are in from a new study of public perceptions of the electric utility industry, and along with attitudes on nuclear power, electric company efficiency, and conservation benefits, it is concluded that most Americans view electricity more as a "right" than as a commodity to be bought and sold.

This last finding, according to Planmetrics, Inc. that conducted the study for the Department of Energy, "implies a legitimate role for an independent governmental agency, divorced from current public utility commissions, in setting rates and insuring an adequate future supply of electricity."

This interpretation recalls other, similar public posturings recently by the Department of Energy and certain segments of the electric utility industry.

DOE, for example, in floating a series of controversial public policy changes aimed at assisting the utility industry in meeting its future power supply commitments with adequate capital, noted that a stronger role for states was being contemplated at the federal level. Each state, under the new plan, would act as a corporate entity to make binding all public utility commission decisions on supply and future financings (*EL&P*, January, 1983 page 1).

The Planmetrics study was carried out as part of DOE's ongoing Energy Electricity Policy Project.

Similar remarks regarding the creation of a new state agency have been heard recently from Arizona Public Service Co. chief Keith Turley. As part of his now oft-quoted comments on how he would no longer build new power plants without a broad consensus of community participants, Tur-

Continued on page 2

Recovery has begun: Reagan

ST. LOUIS, MO—It's official. Economic recovery has begun. En route to this midwestern town to talk to a business group in early February, President Reagan told a *St. Louis Post Dispatch* reporter that the economic recovery he has been predicting for over a year has finally arrived.

"I think the recovery has begun," Mr. Reagan said. "I have to put it that way. For eight out of those [past] nine [months], all economic indicators are up."

The *Wall Street Journal* account of the president's remarks added that, although other administration officials have made similar statements recently, White House officials confirmed that this was the first time Mr. Reagan himself had gone on record proclaiming the end of the recession.

A check with the White House by *EL&P* effectively verified the first-time declaration by the president. "It was not an official announcement," a White House spokesman said. "But as far as I am aware, the president has never said that before."

Foreign Power Briefs

- **Brazil** has delayed plans to build West German-designed nuclear reactors because of a lack of funds, according to the Ministry of Energy. Angra-2 and -3 will be delayed until 1989 and 1990, respectively.

- **Italy's** state energy company, Ente Nazionale Idrocarburi, received a $15 million contract from the Egyptian oil group, Petrobel, to supply an electric plant powered by gas turbines. Scheduled for completion in 1984, the plant will supply electricity to the oil fields at Abu Rudeis, in the Sinai Peninsula.

- **British Petroleum's solar systems subsidiary** will construct a 30-kw solar power plant, largest in the UK, at the Central Electricity Generating Board's Marchwood plant site near Southampton. The installation, which will be 50 percent funded by BP and the balance by the Department of Industry and the European Economic Community, will consist of 960 panels, each consisting of 36 photovoltaic cells. Construction is expected to be started in June.

- **Saudi Arabia** has discovered coal. The Saudi Embassy in Washington reports that a coal deposit, 30 to 45 ft thick covering a 200-sq. mile area in the north of the country, was found. The coal field is located about 350 miles west of the Ras Tanura oil fields on the Persian gulf.

- **Korea Electric Power Corp.**, South Korea's largest electric utility, signed a 15-year contract with Alaska to purchase 800,000 metric tons of coal yearly from the Usibelli mine in interior Alaska. This is the first export contract for Alaskan coal.

- **The South African Electricity Supply Commission** is trying to raise approximately $550 million through international capital markets. The money will be used to finance the purchase of six 600-MW turbines from British General Electric Co..

- **Soviet leader Yuri Andropov** has proposed that a standing commission on energy be set up by the Supreme Soviet to supervise a program calling for the thrift use of energy and "to call to task economic managers of any rank for wasteful use of resources." Observers say Andropov's push for a renewed conservation drive conincides with his attempt to stir the economy.

- **A Swiss** photovoltaic generating plant is delivering power to the city of Lugano, Switzerland. The project is designed to study technical and safety aspects of such systems. The 10-kW demonstration is a joint effort of the Bellinozona Dept. of Environment and the Scuola Technica Superiore in Lugano. A data collection system at the site continuously measures significant electrical and meteorological data.

- **Ontario Hydro** has developed a process to remove low-level PCBs from mineral oil. Dr. Tony Jackson, a Hydro scientist, said that instead of burning the oil, Hydro uses elemental sodium to cause a selective chemical reaction. The oil then can be recovered and used again, while the PCBs are converted to harmless residue. Jackson said the utility is now developing portable processing equipment to treat its insulating oil containing low levels of PCBs.

- **Radio Moscow** reports that an electric railway line between Juffa in the Soviet Union and Tabriz, Iran, is in operation. The broadcast said the railway was built with Soviet aid and is being run by Soviet-trained Iranians.

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EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (••). All readers receive EL&P's industry news section.

Consumer study . . . from page 1

ley called for the creation of a new committee to review and endorse (or reject) utility plans for new power plants. To be established under the aegis of the state regulatory commission, the committee was to include persons representing major societal interests: labor, academia, consumer groups, state government, business, etc. (*EL&P*, January, 1983, page 1).

The study, called "Public Perceptions of Future Electric Supply, Utility Financial Conditions, and Related Issues," is composed of two parts. Public attitudes were probed qualitatively through a series of interviews held across the U.S., and a national survey attempted to measure consumer attitudes quantitatively. More than 1,250 persons participated in the effort.

Electricity as a 'right'

The idea that electricity is perceived more as a right than as a product was said to have emerged spontaneously in the interviews. The most striking example of this, the report notes, was the response of one participant who compared shutting off electricity with "taking away our pursuit of happiness."

The report describes how this finding leads to the conclusion that it may be necessary for the formation of a new government agency to set electricity rates and insure an adequate future supply of electricity.

The first argument hinges on the notion of "abstract entitlement,"—the idea that citizens are entitled to rights, regardless of their specific financial or other conditions.

Second, "rights are necessities." But so are some products, like shoes. Thus, the report concludes, the idea of necessity does not by itself adequately demarcate rights from some basic products.

Protected rights

Third, government should protect rights. "Unlike for commodities or products, there is a pervasive feeling that government should protect and guarantee rights," the report says. "There is an appropriate role for government in the utility industry, and utilities are not simply businesses like any other businesses."

Finally, the consumer attitude report notes that electricity was often compared to air and water not to food and shelter. "Significantly," the report states, "air and water can be grouped as 'environmental concerns,' and to that extent, electricity is an element of a set [of natural bestowments] that participants see as threatened by the private sector and requiring some government intervention."

Added to these arguments are the findings that senior utility management has been deficient in such things as long-range planning, adjusting to the inflation associated with construction projects, construction quality, and personal concern for individual customers.

Also, there was found to be an increasing view that public utility commissions favor utilities over customers in setting rates.

Conservation 'backlash' recorded

Many study participants reported disappointment that conservation measures they have implemented have not reduced or stabilized electric bills. Those who had spent considerable sums weatherizing their homes were found not to have followed through to actually calculate the benefits of their actions, and were said to be discouraged that neither the utility nor the government provided adequate ways to make these calculations in a straightforward way.

In addition, the consumer attitude report found "active hostility on the part of some participants to continuing and/or expanding their conservation efforts."

"This anti-conservation reaction is a new phenomenon and requires greater in-depth exploration than was possible in this study," the report noted.

Notwithstanding this, those who conducted the study offered some "tentative and exploratory" reasons possibly underlying this conservation backlash.

Reasons for backlash

First, conservation efforts may have produced exaggerated expectations of results. "An actual lowering of the bill, rather than a 3 to 5 year payback, becomes the expectation for conservation efforts," the study found.

Second, there was seen to be a general confusion about the amounts of electricity used for various appliances and purposes. This, in turn, led not only to confusion about which appliances really can save electricity but to distorted expectations on potential savings.

Third, it was found that consumers believe the electric company has increased unit charges to make up for lower electricity consumption stemming from conservation. Moreover, these increased unit charges were mostly believed to be going to utility profits rather than to cover fixed costs. According to the study report, consumers used the word "rip-off" to describe this perception of profit-taking.

Other reasons offered for this conservation backlash included suspicion of conservation contractors, suspicion of energy audits, and ambiguity about "soft path" approaches.

Other findings reported

The DOE consumer attitude study also revealed that utilities are perceived to be in good to excellent financial condition overall.

Also, a majority of Americans think electricity rates are excessive.

Americans tend to be divided on the value of electricity: some think they are getting a good value at present, while others were found to take electricity for granted.

There is a continuing concern for environmental quality, the study found. There is little present support for reducing environmental regulation, although "projections of an environmental quality mind-set suggest increasing support for some lessening of regulations in the coming decade."

Nuclear debate divides

Finally, nuclear energy continues to divide Americans. In the national survey part of the study, 45% of those queried were found to favor the use of nuclear energy, with 34% opposed and 20% in the "don't know/depends" catagory.

Sixty two percent of the respondents felt the utility industry has not been honest about the cost of nuclear power (21% believed the industry has been honest; 18% didn't know); and 64% of those queried said the utility industry has not been honest about nuclear power safety.

Copies of the report (DOE/PE/70009-1) are available from the National Technical Information Service, U.S. Department of Commerce, Springfield, Virginia 22161.

‘Replacement’ depreciation could exceed CWIP benefits

KANSAS CITY, MO—Electric utility rate makers may be well advised to seek replacement or economic depreciation from public utility commissions rather than arguing for greater construction work in progress (CWIP) in rate base, a noted utility analyst has affirmed here.

"The expedient of phasing construction work in progress into rate base has little foundation in economic theory," Wallace W. Carpenter, vice president of Ebasco Business Consulting Company said.

"It becomes price effective too little and too late to influence the demand that required the added plant," Carpenter said.

Simply put, economic depreciation provides a more liberal allowance, in the face of inflation, to maintain the value of investments in utility property rather than the more traditional approach taken by state commissions to maintain original cost investments.

Construction work in progress in rate base allows an electric company engaged in a generating plant building program to collect from ratepayers interest charges on construction expenditures before the plant is actually in service. It thereby provides the company with a present return on its invested capital.

Allowance for funds used during construction (AFUDC), conversely, is the accounting utilities are allowed which aggregates and defers collection of this return on invested capital until such time as the plant becomes "used and useful."

The depreciation scheme advocated by Carpenter would increase cash flow during the construction period over the use of AFUDC, which is, after all, simply a promise that invested capital and the foregone interest on that invested capital will be recouped once the plant becomes operational.

This replacement or economic depreciation scheme not only provides higher quality earnings than AFUDC during the construction of new generating units, but it has advantages that outweigh the use of CWIP in rate base as well, Carpenter believes. "CWIP in rate base is the spot application of water to put out a local fire," he said by way of analogy, whereas the use of economic depreciation provides more general relief as it becomes part of the cost of service whether or not an electric company actually intends to build a new expensive base-load generating plant.

Further, economic or replacement depreciation provides customers with up-front price signals. "Over a period of years, the pre-collection of depreciation charges on a replacement basis will have had a full opportunity of influencing the capacity of requirements through the known effects of price elasticity," Ebasco's Carpenter said.

The Ebasco consultant promoted replacement depreciation over the more traditional original-cost depreciation accounting before attendees at the 9th annual rate symposium here sponsored by The Institute for Study of Regulation.

For electric utilities that perceive it is in their interest to forestall the construction of new power plants as long as possible, the consideration of economic depreciation, and its advocacy before public utility commissions, could result in added revenues, although this may be at the expense of kilowatt-hour sales. According to comments by recent utility executives and by Department of Energy policy makers, present financial and service obligation pressures do seem to be moving industry thinking more toward acceptance of unconventional ideas than has historically been the case (see *EL&P*, two stories, page 1, January, 1983).

However, the idea of replacement depreciation, resulting in depressed energy sales due to the higher price signals communicated to the customer, may not be welcomed by utility managers who have large reserve margins or who are otherwise disinclined to implement policies that reduce output.

Carpenter is not dreamily sanguine that those state regulators that have steadfastly denied even nominal increases in original cost depreciation expenses (e.g., by the adoption of equal life grouping of assets) will suddenly rush to embrace replacement cost depreciation.

"But that is their (the regulators') ultimate task as I see it," Carpenter said, adding that there has been progress in this area as seen by recent steps taken by the federal commission regulating the communications industry.

One potential stumbling block to economic depreciation accounting is the fact that under this method overall revenues may be expected to increase roughly 5 to 15 percent.

In addition, utility and regulatory accountants may be disturbed by the failure of economic depreciation to provide complementary balance sheet accounting.

A substitute for deregulation

Given that the main objective of deregulation of power supply is to provide, outside of a regulatory environment, the capital necessary to build new generating plants, Carpenter believes that the implementation of economic depreciation might achieve the same objective at a much lower cost.

In a recent analysis of the subject, he observes that under deregulation, diversified ownership of power production facilities would require a valuation of existing plants so that transactions between plant sellers and buyers would be possible.

Such valuations would have to be based on some definition of "fair value," and Carpenter sees this as approximating replacement costs if these plants are "to achieve their equivalent quality of output over their remaining life."

"Thus," he argues, "any deregulation scenario implies the substitution of the new owner's greater capital recovery costs in the pricing of each conveyed plant's output, instead of the present components of capital recovery-depreciation of original cost and return on the undepreciated balance of original cost."

Under standard ratemaking methods, capital recovery consists of two components: depreciation, or the return *of* capital; and earnings based on the unamortized capital balance, or the return *on* capital. Economic or replacement depreciation would substitute for the former component, and according to Carpenter, "might generate cash flow adequate to finance most utilities' capital requirements in either an inflationary or deflationary scenario."

Among existing applications of this idea is the report that England mandated the use of replacement depreciation accounting for all of its industry in 1980, and the Financial Accounting Standards Board (FASB) has required such reporting on an informational basis for several years through FASB Statement No. 33.

Advantages cited

Carpenter points out that beyond its basic intent to preserve capital, economic depreciation has several advantages.

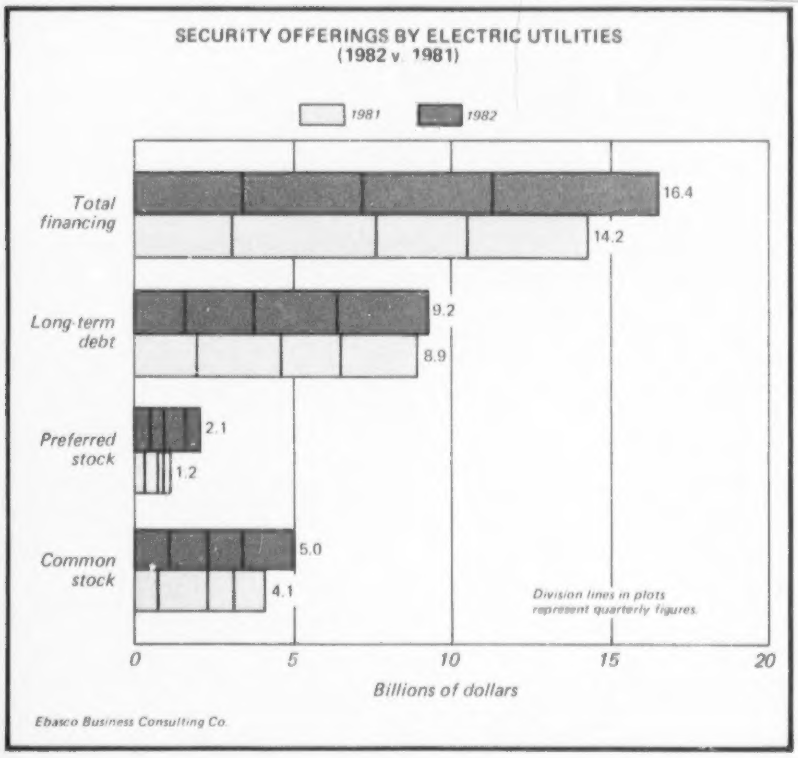
First, it should be more acceptable to regulators than power supply deregulation because under economic depreciation electric utilities are still under their traditional obligation to meet consumers' service needs; investors reap no windfall return; and no "fair value" pricing concept is required.

Second, the computing and reporting experience garnered under FASB 33 could be employed in implementing the idea more widely.

Third, economic depreciation complements marginal cost pricing by more closely approximating real market economics of power supply. Intergroup ratemaking distortions introduced in writing down the excess of marginal cost over embedded cost are seen to be greatly reduced.

Finally, it is a more permanent solution to the ravages of inflation than inclusion of CWIP in rate base.

Electric utility financing up in '82



Ebasco Business Consulting Co.

NEW YORK—Total utility financing in 1982 was $20.8 billion, a decrease from the 1981 total of $21 billion.

A report prepared by Ebasco Business Consulting Company shows electric utility financing jumped 15 percent from $14.2 billion in 1981 to $16.4 billion last year.

Long-term debt issued by electric utilities rose slightly to $9.2 billion from a 1981 total of $8.9 billion. Total long-term debt issued by all utilities dropped from $14.5 billion in 1981 to $11.6 billion in 1982.

Preferred stock financing by electric companies almost doubled in 1982 from $1.2 billion in 1981 to $2.1 billion. Offerings of preferred stock by all utilities jumped sharply to $2.5 billion from $1.3 billion in 1981.

Common stock financing for electric utilities was $5 billion last year, compared to $4.1 billion in 1981. Total utility common stock financing also was up from $5.3 billion in 1981 to $6.6 billion last year.

JESCO opens new office

FULTON, MS—JESCO, Inc. has opened a division office in Montgomery, Alabama.

A subsidiary of AMCA International Corp., JESCO is a construction and engineering company serving industrial and construction clients across the South.

Letters . . .
from page 4

He declared:

> This bill was put forth by its proponents as a bill for the protection of the public. This amounts to making a virtue out of a subsidy. This bill is protective of large utilities, industrial companies, and insurance companies which [sic] are not willing to adhere to the tenets of free enterprise ...
> This bill is not a minor technical amendment to the Atomic Energy Act. It is a major piece of legislation. It goes far beyond anything I know in committing the federal government to future liabilities without any clear understanding or basis in experience as to the nature or magnitude of these liabilities.

Unfortunately, this historic warning has been ignored. The lobbying for this bill apparently had been managed so skillfully that the Act was passed in both Houses of Congress without even recording the vote!

By contrast, special commendation is in order for having reported on the shocking realities on the Zimmer and Seabrook Nuclear Power Plants in your February issue. What has become of the sense of responsibility of the Board of Director levels in these two companies, or the so-called distinguished leaders and spokesmen in such companies?

Adolph J Ackerman
Consulting Engineer
Madison, WI

Volume-reduction radwaste processing slashes O&M costs

Richard Beaudry
Detroit Edison

Richard Keenan
WasteChem Corp.

Detroit Edison has decided to upgrade the low-level radwaste processing system installed at the Fermi 2 nuclear station, which is still under construction and is slated for operation later this year. Rising radwaste system operating costs and the changing status of low-level radwaste burial grounds since the original decision was made for a cement-type system led to the reappraisal. The retrofit is expected to reduce low-level solidified radwaste volume from 7000 drums a year to only 500 and reduce annual overall system O&M cost from \$9.5 million to \$1.5 million, as shown in the table.

Fermi 2 is a nominal 1100-MW BWR-4 for which detailed engineering began in 1968. The original commercial operation date was 1976 but delays have pushed that back to late 1983.

The low-level radwaste systems (liquid and solid) purchased as part of the overall plant were typical for that generation of BWR plants and represented the existing, state-of-the-art technology. Included as part of the original plant were early-generation liquid processing and solidification systems. In addition to being plagued by many operating problems, those early systems were not necessarily compatible with the changing economic climate in which waste disposal and handling costs have increased dramatically.

These changes caused Detroit Edison to reexamine its radwaste systems with the intent of updating them to incorporate cost-effective and proven advances in technology and to comply with changing requirements. This reexamination was performed after most of the radwaste systems had been installed, but prior to initial checkout and pre-operational testing.

Rising costs

The principal costs associated with operating a radwaste solidification system cover the binder, end-product containers, transportation to the burial site, and burial. Labor requirements, which vary widely among radwaste systems and to some extent from one utility to another, can also be significant. All costs have risen but the increases for some items far exceed inflation. Of particular note are the increases in burial and transportation costs. There are fewer burial sites, higher fuel costs, and more stringent regulations.

The escalation of the major cost categories in the last five years is shown in Table 1. The table uses 1976 as the base because that was the original operation date. The 1981 costs are presented because they were the values in effect at the time the reappraisal took place. Since then costs have climbed further to the values shown in the third column.

Transportation costs

To obtain a better understanding of why the retrofit decision was made, consider just one aspect of the costs, transportation. In 1976 the nearest low-level radwaste burial site was in Sheffield, Illinois. The round-trip distance was 800 miles and the estimated transportation cost was \$600 (escalated to \$1200 today.)

Since 1976 the burial sites east of the Mississippi have either closed or instituted an allocation system that, for practical purposes, has closed the door on any full time usage for Fermi. When Sheffield closed—and with the sites at West Valley, N.Y. and Maxey Flats, Kentucky already closed—the nearest burial site was at Barnwell, South Carolina, a one-way distance of 1200 miles. Regulations now in effect at Barnwell, but not in effect in 1976, will severely limit the number of shipments which are accepted from Fermi 2.

This forces Detroit Edison to go to Beatty, Nevada or Richland, Washington, both approximately 2000 miles away, one-way. The cost in 1976 to go to either of these sites would have been about \$3000 for a round trip, rising to \$6000 in 1981.

To summarize, the 1976 cost of \$600 per round trip to Sheffield has escalated to a 1981 cost of \$6000 to a western site. If the original Fermi 2 cement radwaste solidification system had been used, then about 600 shipments would have been expected each year. Transportation costs for 600 shipments per year to various burial sites, for 1976 and 1981, are summarized in Table 2.

The overall cost climbed from an original low of \$360,000 for Sheffield to \$3.6 million to a site in the West. Although the plant was not yet operating, Detroit Edison recognized what was happening to these costs and authorized a detailed study to be made by the NUS Corp. This study examined the various costs associated with upgrading and updating the installed liquid radwaste and cement solidification systems, as well as replacing the cement system with a volume reduction system.

Numerous modifications to the existing systems were examined. The net result was that three major viable alternatives were proposed:

A. Minimum modifications the existing systems required to improve its operating performance.

B. More significant modifications aimed at reducing the waste input to the drumming station, upgrading of the cement system, and more general upgrading to current standards.

C. Retrofitting a volume reduction system, plus any of the above upstream modifications considered to be cost-effective.

Factors covered in the evaluation included capital costs, present worths and payback times, operational ease and flexibility, expected operational and maintenance problems, ALARA considerations, and the potential for adjustment to future regulations. All cost items were converted into total present-worth values, which were the major factors Edison used in its final determination. One portion of these study costs, the annual operating and maintenance (O&M) values, is summarized in Table 3.

Detroit Edison chose alternative C, a volume-reduction retrofit. Engineering design has now been completed, the original cement system has been removed from the radwaste building, and the radwaste volume reduction system has been delivered and installed.

As shown in the table the volume reduction system significantly reduces the number of drums of solidified radwaste produced annually. This is caused, to a large extent, by the most distinctive change included in this option as compared to the other two—the addition of a Werner & Pfleiderer VRS System. This is a one-step volume reduction and solidification process which uses an extruder-evaporator to evaporate the water from the liquid radwaste feed while simultaneously mixing the dried residual solids with an asphalt binder. It processes both resins and waste concentrates. Part of Detroit Edison's evaluation of the VRS System included having utility personnel visit Europe to observe similar installations in operation and to talk with operators. It was confirmed that asphalt solidified wastes are acceptable at all the burial sites. The Topical Report for the VRS System is accepted by the USNRC for reference in a plant's Safety Analysis Report, thereby simplifying licensing.

The direct economic benefits alone justified the retrofit decision, but the regulatory, technical, and operational considerations have assured Fermi 2 that the overall system will perform with good operability and low maintenance and will meet any expected regulatory and/or burial criteria. For any utility evaluating today's volume reduction and solidification technology, it is important to note that non-volume reducing radwaste systems with a low capital cost but a high operating cost may not prove to be a good investment on an evaluated-cost basis. The system that has the best evaluated cost, coupled with high operational reliability, is often the system to purchase. Even with today's high cost of money, volume reduction technology proves to be a very wise investment.

TABLE 1
ESCALATION OF MAJOR OPERATING COSTS

	1976	1981	Current
Binder			
Asphalt	4.5¢/lb	9.5¢/lb	10.0¢/lb
Cement	2.0¢/lb	3.5¢/lb	4.0¢/lb
Polyester	95.0¢/lb	\$ 1.30/lb	\$ 1.30/lb
Containers (55-gal drums)	\$15.00/drum	\$20.00/drum	\$21.00/drum
Transportation	\$ .75/mile	\$ 1.50/mile	\$ 1.50/mile
Burial	\$ 3.50/ft^3	\$11.60/ft^3	\$15.75/ft^3

Note: Transportation and burial cost figures do not consider such factors as waste activity, cask requirements, etc. Therefore, the actual costs would normally be expected to be somewhat higher.

TABLE 2
COMPARISON OF ANNUAL TRANSPORTATION COSTS
FROM FERMI 2 TO VARIOUS BURIAL SITES
USING ORIGINAL CEMENT SYSTEM

	Sheffield, IL	Barnwell, SC	Richland, WA
1976	\$360,000	\$1,080,000	\$1,800,000
1981	\$720,000	\$2,160,000	\$3,600,000

TABLE 3
COMPARATIVE STUDY RESULTS OF TOTAL ANNUAL (1981) O & M COSTS

	Unit Cost	Total
Alternative A		
1. Operators around-the-clock (8 men)	\$ 17.00/hr	\$1,191,360
2. Consumable supplies (resin, etc.)	–	400,000
3. Maintenance (parts & labor)	–	142,000
4. DAW (1,300 drums)^a	\$ 122.00/drum	158,600
5. Cement	\$ 8.75/drum	61,250
6. Shipping & burial—solidified liquids (7,000 drums)^c	\$1,080.00/drum	7,560,000
	TOTAL	\$9,513,000
Alternative B		
1. Operators around-the-clock (5.5 men)	\$ 17.00/hr	\$ 819,000
2. Consumable supplies	–	72,600
3. Maintenance (parts & labor)	–	108,000
4. DAW (930 drums)^b	\$ 122.00/drum	113,460
5. Cement	\$ 8.75/drum	17,500
6. Shipping & burial—solidified liquids (2,000 drums)^c	\$1,080.00/drum	2,160,000
	TOTAL	\$3,291,000
Alternative C		
1. Operators around-the-clock (4.5 men)	\$ 17.00/hr	\$ 670,140
2. Consumable supplies (includes asphalt)	–	91,100^d
3. Maintenance (parts & labor est.)	–	104,000
4. DAW (930 drums)^b	\$ 122.00/drum	113,460
5. Shipping & burial—solidified liquids (500 drums)^c	\$1,080.00/drum	540,000
	TOTAL	\$1,519,000

Notes: a) Shipping and burial costs for Dry Active Waste-original compactor.
b) Same as above, but with improved compactor.
c) Includes drums, transportation, burial, and cask fees.
d) Cost of asphalt is \$12,500 annually.

Economist sees small coal-fired plants in many utilities' future

ELECTRIC GENERATING COSTS FOR COAL PLANTS BY SIZE FOR SUBCRITICAL AND SUPERCRITICAL UNITS

Size (MW) (1)	Capital Cost ($/kW) (2)	Equivalent Availability (3)	Heat Rate (MMBtu/kWh) (4)	Levelized Annual Costs Capital (5)	O&M (1982 Cents/kWh) (6)	Fuel (7)	Total (8)
			Subcritical Unit				
200	1,136	0.841	9,530	1.23	0.41	2.01	3.65
400	975	0.735	9,530	1.21	0.43	2.01	3.65
600	892	0.691	9,530	1.18	0.46	2.01	3.65
800	837	0.668	9,530	1.14	0.49	2.01	3.64
1000	797	0.654	9,530	1.11	0.52	2.01	3.64
			Supercritical Unit				
200	1,366	0.656	9,225	1.90	0.45	2.01	4.36
400	1,052	0.640	9,225	1.50	0.45	2.01	3.96
600	904	0.635	9,225	1.30	0.47	2.01	3.78
800	812	0.632	9,225	1.17	0.50	2.01	3.68
1000	748	0.631	9,225	1.08	0.53	2.01	3.62

Source: "The Current Economics of Electric Generation from Coal in the U.S. and Western Europe," by Lewis Perl, National Economic Research Associates.

NEW YORK—National Economic Research Associates has released results of a study by firm vice president, Lewis Perl, that shows the future of utility generation belonging to small coal-fired power plants, rather than the big, 1000-MW nuclear units favored in the past.

First, Perl predicts that utilities will favor coal over nuclear in their base-load generation plans. His levelized energy cost analysis similar to the study released by the Dept. of Energy recently (see *EL&P*, October, 1982, pg. 19), shows that electricity from nuclear plants, on average, will cost only slightly less than electricity from coal plants. Given this closeness in a pure cost comparison, the nod will go to coal, in Perl's opinion, for these reasons:

- The uncertainty in forecasting future nuclear costs is much larger than that for coal plants.
- The longer construction time for nuclear plants—eight years on average compared to five for a coal plant—creates greater financial risks by making it more difficult to adjust to unforeseen declines in load growth.
- Since nuclear power is more capital intensive (capital costs account for two-thirds of nuclear electricity costs vs. one-third for coal), the risks of cost overruns are much greater.

Consumers are sensitive

- Nuclear costs are high-front-end loaded due to their capital intensive nature. That means that the electricity cost advantage of nuclear vs. fossil fuel options doesn't show up for the consumer until the plant has operated for at least seven years. "Consumers tend to be very sensitive to the short-run effects of new generating facilities and less sensitive to their long-run savings," says Perl. (That factor may also discourage the replacement of existing oil-fired capacity with new coal plants.)

"Consequently," Perl concludes, "given the risks and uncertainties associated with nuclear power, their small cost advantage is not likely to induce utilities to put all their eggs in that basket. While most of the nuclear plants currently under construction in the United States will be completed, future construction beyond 1988 is likely to be predominantly coal."

Small coal

The future belongs to small coal plants—less than 600 MW in size—because there are not only no economies of scale, there are diseconomies of scale, according to Perl. The economist bases his conclusions on the figures in the table. While construction costs drop as unit size increases, availability worsens, producing a standoff in levelized costs.

"When both the subcritical and the supercritical technologies are considered," says Perl, "economies of scale prove to be very unimportant. In the range of 800 MW and less, the subcritical technology appears to be cheaper and this technology exhibits no scale economies. While very large supercritical units tend to be cheaper than very large subcritical units, the advantage is too small to be significant. Moreover, since small units offer substantial planning and reliability advantages, it would appear that there may actually be diseconomies of scale in the construction and operation of coal-fired facilities."

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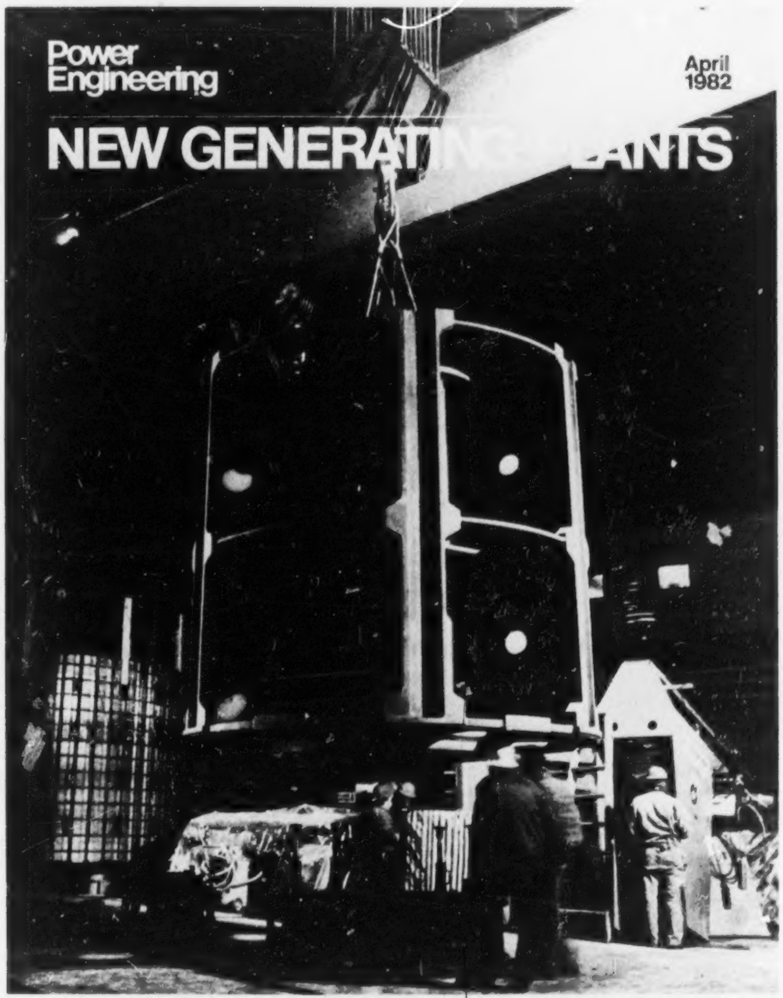

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Westinghouse gets two DOI hydro uprate jobs

WASHINGTON—The U.S. Dept. of Interior announced that it has awarded contracts to Westinghouse to upgrade hydroelectric generating equipment at the Glen Canyon and Glendo power plants.

Eight units involved

The $12 million Glen Canyon job involves all eight units and will uprate station generating capacity from 125 MVA to 165 MVA. Work includes replacing or insulating field rotor windings and armature windings (four generators will be rewound), strengthening rotor arms, and modernizing voltage regulating equipment.

The $1.5 million Glendo project in Platte County, Wyoming will uprate two hydroelectric generators from 12 MW to 19 MW.

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April 1983

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

SoCalEd's Gould is Man of Year

CHICAGO—Southern California Edison Co. Chairman and Chief Executive Officer William R. Gould has been named Electric Industry Man of the Year for 1983.

Readers of *Electric Light & Power* voted Gould the honor. Robert A. Lincicome, *EL&P* editor, said in announcing the award that Gould was honored for his "early recognition of changing social and economic concerns in his company's service territory, resulting in development of a broad, balanced energy resources program that includes conventional, nuclear, renewable and alternative energy sources, and strong conservation programs, and for a long and distinguished career of service to the electric industry and the engineering profession."

The award will be presented to Gould at the All Engineers Dinner at the American Power Conference in Chicago on April 19. The presentation, which will be made by Lincicome, carries with it a $1,000 contribution in Gould's name to the University of Utah, Gould's *alma mater.*

Profile begins on p. 13

Ted Stern, executive vice president nuclear energy systems for Westinghouse Power Co., will be the featured dinner speaker.

Gould is the eighth man to receive the *EL&P* award. Last year's recipient was A. David Rossin, director of the Nuclear Safety Analysis Center.

William R. Gould, 1983 Electric Industry Man of the Year.

Move to telecommunications by power companies seen

WASHINGTON, D.C.—The break up of AT&T, the advent of new technologies, and the political and financial difficulties being encountered by cable companies have combined to make the time right for electric companies to move into telecommunications.

According to attorney Steven R. Rivkin, "Pyramiding on unmet (and sometimes unappreciated) needs to enhance load-factors, electric companies are well-positioned for either direct entry into or joint ventures with telephone or cable television companies."

Rivkin, who spoke at the Tenth Energy Technology Conference here, said that a relatively straightforward re-deployment of utility assets could be expected to have an enormously beneficial impact on both the energy and the telecommunications industries, on consumers, and on the economy as a whole.

Not only would there be potential profits from entertainment television, but there could be significant efficiency gains flowing to electric companies as they enhance load factors through the use of telecommunications.

Precisely calibrated commercial and residential time-of-day rates, load control, distribution automation, and accurate, in-depth load research are some of the advantages foreseen. In addition, telecommunications could provide the framework for the orderly pricing of co-generated power, with electric companies systematically acting to create markets for this power by instantaneously determining prices.

Further, it is envisioned that major improvements in cash-flow would occur as a result of speeded up billing and payment through communications links. New marketing opportunities for load-leveling technologies (for example, electric cars and electric storage heaters) would likely follow when time of day prices and associated marketing strategies had begun to materialize.

Finally, utilities could be expected to gain leverage in capturing a major segment of the exploding markets for "local loop" telecommunications and associated information business.

While cataloging the potential benefits that might flow from the deployment of telecommunications by power companies, Rivkin observes what he sees as some of the obstacles confronting the transition. "It will be a tall order," he says, "for the electric industry to reverse historic directions, from its all-too-prevalent, ongoing conflicts with consumers and regulators to the assiduous courtship of consumer appetites for energy and information services which the forecasted transition implies."

Institutional barriers falling

Attorney Rivkin says that the institutional barriers to power company entry into the telecommunications business, as perceived by utility executives, are slowly but surely falling away. "To me," he said, "it is already clear that there really are no regulatory barriers on the telecommunications side."

Rivkin said that the Federal Communications Commission doesn't block entry into the communications business by "outsiders," as it does, for example, for telephone companies, broadcasters, and possibly newspapers from getting into cable. Although state agencies regulate telephone service as a monopoly, the advent of local-loop competition is not expected to give regulators much pause.

Continued on page 3

Nuclear outlook gloomy through 2000, OTA finds

Dan Utroska
Associate Editor

WASHINGTON, D.C.—Absent extraordinary events worldwide, new orders for nuclear reactors are not likely for at least the next 15 years, the Office of Technology Assessment has concluded.

Although the results of a year-long investigation for the House Science and Technology Committee are pessimistic about new reactor orders before the year 2000, the study revealed an unexpected staying power on the part of the nuclear industry: even as nuclear plants are completed or cancelled over the next decade or so, the capability to build new reactors will not be completely dismantled.

"Things look very gloomy," OTA project leader Alan Crane told *EL&P*. "There is a lot that can be done to revive the industry, but more must be done by industry [as opposed to the federal government]. Whether enough gets done to see new nuclear orders this century looks doubtful to me."

One of the things that Crane believes the nuclear industry could do to stimulate new plant orders would be to reduce the size of the reactors. He says the large reactor manufacturers, such as Westinghouse and General Electric, continue their trend toward ever larger nuclear plants because they believe electric utilities are more inclined to struggle their way through the licensing process one time for, say, a 1,200 megawatt plant, rather than twice for two 600 megawatt plants.

"It is their perception that this is what utilities want," Crane said, adding, "I don't sense this at all."

Crane said plants of 200-MW would probably be too small, but units in the 500-700 MW range would be ideal, particularly if the entire plant size could be reduced, rather than just reducing the number of loops.

Smaller plants would mean that larger portions could be built in the shop, rather than in the field, Crane said, and this would mean lower cost and higher quality, generally. This, in turn, would translate to plants of higher reliability.

Crane concedes that the smaller units will cost more dollars per kilowatt, but the differences between the larger units would not be great. "The old [cost] scaling factors are obviously not valid anymore," he says.

He calculates that the slightly higher costs of the smaller nuclear units probably would be more than made up for by reduced construction times and the concomitant lower financing costs.

Industry to survive hard times

To OTA researchers, one of the more surprising findings of their in-

Continued on page 2

Foreign Power Briefs

- **The Trinidad and Tobago Electricity Commission** bought a $63 million combined-cycle steam and gas-turbine plant from General Electric Company. The 198 MW plant is the first combined-cycle equipment bought by the island nation. General Electric has 51 combined-cycle plants operating or on order world-wide.

- **Electricite de France,** the French publicly-owned utility, got a 13 percent rate increase from the government. President Francois Mitterrand had set an 8 percent target level for the cost of living index. However, the utility suffered through an extremely bad year and was successful in persuading the government to grant the higher increase.

- **The UK government** should increase its investments in energy conservation, says a report from the Association for the Conservation of Energy. The report compared energy conservation programs in the UK with other European Economic Community countries, and concluded that "the energy conservation program of the UK is now distinctly limited, certainly compared to the more ambitious schemes undertaken by other countries."

- **Caracas, Venezuela's** C.V.B. Electrificacion del Caroni C.A. has awarded a contract to ASEA for delivery of two 800-kV static compensators to be installed in the San Geronimo and La Horqueta substations. They will be used to stabilize the voltage in the 800-kV transmission system between the 10,000 MW Guri Hydro station in the Orinoco delta and the Caracas load center.

- **A Canadian Electrical Association study** on residential energy attitudes reveals that 10 percent of canadians think acid rain is caused by nuclear power stations and that wind power will preempt fuel oil and coal in 20 years. In a national sampling of 2,500 Canadians, the report also found that two-thirds of those polled believed more generating plants will have to be built within the next five years. One-third of all homes in the country are heated by oil and a third of those are considering conversion to electricity, says the association study.

- **The Energy-Economic Institute of Cologne University** in West Germany issued a report that says, "Despite the leap in oil and gas prices, large plants in West Germany for coal gasification and liquefication—even using the relatively cheap imported coal—are still far removed from becoming an economic proposition." The authors conclude that the country's work in advanced coal technology will require government support to move beyond the research and development stage.

- **Tokyo Electric Power Co.**, Japan's largest utility, is negotiating with West Germany's Kraftwerk Union to purchase a 1,300 MW pressurized water reactor. The Japanese utility has used BWRs designed by General Electric, but says it would like to add German-designed PWRs from 1985 on. A spokesman for Kraftwerk said an agreement is expected to be reached sometime later this year.

- **Israel's cabinet** approved a plan for building nuclear plants. Science Minister Yuval Neeman told the cabinet that Israel can build all parts for the facilities if foreign suppliers won't sell to the country. No date has been set for construction of a plant.

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ELAP readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (••). All readers receive EL&P's industry news section.

Nuclear . . . from page 1

vestigation was the determination that domestic nuclear reactor production capabilities are expected to endure the period of reduced sales. "We had thought it was more ominous than that," Crane said.

He noted that continued service work on the part of reactor manufacturers is likely to be "enough to keep the manufacturing aspects alive even as the assembly lines are shut down."

There will be some attrition along the way, with some large component companies, such as pump and pressure vessel firms, shifting to other product lines or folding entirely. And reactor components ultimately will cost more. But the study group's overall conclusions from discussion with utilities, vendors, and sub-tier suppliers were that if a utility should be interested in purchasing a nuclear reactor in 1995 it probably would still be able to buy it from a domestic producer.

Even though such a reactor might have various foreign components as part of it, it would still be one of U.S. manufacture. "We were not able to identify anything near being a 'show-stopper,'" Crane said.

Study conclusions tentative

Crane emphasizes that findings on the future status of nuclear power in the U.S. are tentative, and could be altered before the final report is released publicly. Currently, the report is expected to be issued sometime around September, 1983.

The OTA investigation consisted of workshops to probe the future of three important aspects of nuclear power: the cost of nuclear plants, potential financing, and the future demand for power.

The workshops have been completed and in mid-March OTA was in the process of preparing its first draft report. Conclusions were expected to be submitted to an OTA advisory panel consisting of some 16 to 18 representatives of industry, manufacturers, utilities, intervenors, and general observers. The intent is to balance opposing viewpoints before the report is submitted to the OTA board for final review and approval. The OTA board consists of 6 U.S. Senators and 6 Representatives.

Westinghouse, GE see orders by '88

Contrary to the findings of the Office of Technology Assessment, both Westinghouse and General Electric expect that there will be new nuclear reactor orders within the next five years.

Also, both of the large reactor vendors believe that the current licensing bramble is a key component in the decision of electric utilities not to build new nuclear plants. However, they generally deny OTA's characterization of the large reactor manufacturers as believing that electric companies would be more inclined to purchase a large 1,200 MW unit rather than, say, two 600 megawatt plants principally because utilities would prefer to go through the licensing process once rather than twice.

Instead, Westinghouse and GE maintain that when electric companies again begin thinking about new nuclear plants, they will opt for the larger units on the basis of economies of scale. Although Westinghouse was not able to offer figures on the cost disparities that might exist between a small and large average nuclear plant, GE calculates that although a smaller unit (of about 600 megawatts) will have a net capital outlay about 15 percent less than a larger plant (of about 1,000 MW), the cost per kilowatt for the smaller unit will be about 40 percent greater, a GE spokesman said.

The greater financing charges for the larger plant were not considered by GE to eliminate the cost advantage of the bigger units. "There is no evidence that either the construction cycle nor operation performance for small plants would be better than large plants," the spokesman said.

It was, in fact, reported to be beneficial for electric companies to contemplate the larger units on the basis of either wheeling excess capacity or sharing a nuclear project with neighboring utilities.

Hodel says gas prices will drop

WASHINGTON, D.C.—President Reagan has sent legislation to Congress that would deregulate the wellhead price of natural gas by 1986.

"We believe the price of natural gas will drop under the President's proposed natural gas legislation," said Secretary of Energy Don Hodel.

Hodel said a Department of Energy analysis shows that natural gas prices would drop from 10 to 30 cents per thousand cubic ft in the first year after enactment of the bill.

The average wellhead price is currently about $2.75 per thousand cubic ft (mcf). For a homeowner, the average is about $5.50 per mcf.

Consumers protected

Deregulation would be accomplished through negotiation of new contracts or renegotiation of old ones. Consumer protection would include a moratorium of automatic pass through costs greater than inflation. And prices that could be charged under old regulated contracts would be limited to the volume-weighted average price of the new contracts or the old controlled price, whichever is less.

"We believe that the consumer must be protected," said Hodel. "We therefore included in the plan a cap on prices, so that prices could not go higher than they would under existing controls. At the same time, we would free the pipelines and producers to negotiate new contracts or renegotiate the old ones which have distorted market prices and in fact make gas cost more to the consumer than under a free market where the supply of gas exceeds demand."

Analysis assumes excess

The DOE analysis includes conservative assumptions concerning world oil prices and GNP growth. It also assumes an excess of available natural gas.

DOE says that under the base case, the average price of gas in the first year would decrease 10 to 30 cents per thousand cubic ft. Assuming low oil prices, DOE says residential gas prices would drop about 30 to 60 cents in the first year, and that would be about 40-70 cents below projected prices under current law.

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$83.6 billion to be spent on R&D in '83; Battelle says

COLUMBUS, OH—Spending in 1983 for research and development will reach $83.6 billion, according to the annual forecast of Battelle's Columbus Division.

The $83.6 billion would be an 8.2 percent increase over the $77.3 billion estimated to be spent in 1982 by the National Science Foundation.

Battelle says that industrial funding will account for $41.4 billion, or 49.6 of the total R&D funding.

The organization reports an increase of 8.8 percent in federal support for R&D, with funding expected to reach $39.3 billion.

Funding by academic institutions is expected to be $1.8 billion. Other nonprofit organizations will provide $1.1 billion.

Four government agencies dominate the federal R&D scene and are expected to account for 91.2 percent of the total federal expenditures for R&D in 1983. They are the Department of Defense, 56.6 percent; NASA, 14.9 percent; DOE, 10.4 percent; and Health and Human Services, 9.3 percent.

The forecast notes that increases in defense spending are primarily directed toward the acquisition of major weapons systems and the R&D that will be necessary to support them. Additionally, it is noted that budgets also are increased for space and general science programs. Battelle forsees continued small-scale increases in these major fields, but declines in energy R&D.

The Columbus organization says funding for energy research will continue to decline since there is little evidence that energy will be perceived as a national problem requiring massive federal R&D support.

Industrial support of research is growing in fields related to electronics, communications, advanced machinery and in those fields most directly influenced by the need for more energy-efficient products and processes.

R&D will be heavily self-funded in the manufacturing industries, where on the average, only 32 percent of the total will come from the federal government.

In 1983, Battelle predicts the electrical machinery and communications manufacturing industries to be the leaders in total manufacturing R&D, with funding of more than $12.8 billion. Of that, 59.1 percent will be industrially funded.

Other industrial sectors Battelle estimates will receive more than $1 billion in R&D monies include:

- machinery—$9.1 billion, 83.3 percent of which will be industrially funded.
- autos, truck and parts, and other transportation equipment—$7.2 billion, with 85.6 percent to be industrially funded.
- chemicals—$6.8 billion, with 90 percent to be industry funded.

Fed support shifts

The report concluded that over the past few years, federal support has tended to shift more toward "development" and away from basic and applied research. If such trends continue, the report said, the long-range consequences may pose significant problems in terms of the science base upon which economic vitality grows.

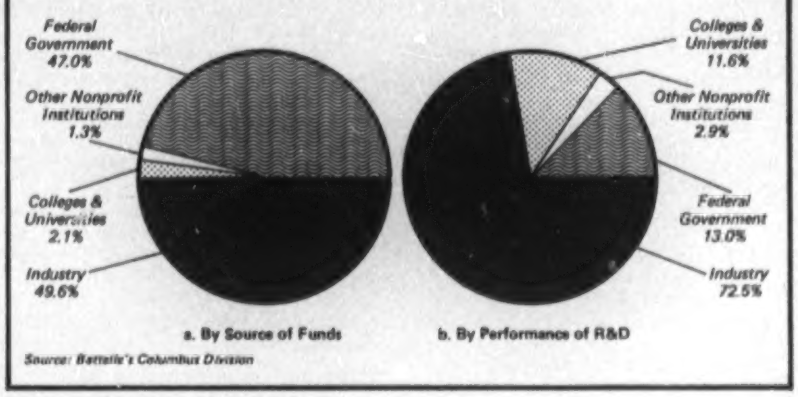
Such problems may, in part, be mitigated by a continuation of the recent resurgence of basic research support by industry, the forecast notes.

However, the volatility of indicators—such as sales, profits and cash flows, precludes stability for long-term planning.

The forecast was prepared by Drs. Jules J. Duga and W. Halder Fisher, of the Department of Resource Management and Economic Analysis at Battelle.

R&D Expenditures in the U.S., Calendar Year 1983

The total forecast by Battelle's Columbus Division is $83.6 billion. Distribution shown here is by source and performance.



a. By Source of Funds

b. By Performance of R&D

Source: Battelle's Columbus Division

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GPU income up sharply; banks renew credit plan

PARSIPPANY, N.J.—Net income of General Public Utilities nearly doubled during 1982 compared with income for the previous year, a report from the electric utility shows.

Net income for the 12 months ending November, 1982 (excluding extraordinary items), was $34.7 million, up 96 percent from $17.7 million for 1981. Extraordinary items, which include credits and debits to net income, was a negative $8.4 million for 1982, contrasted with a negative $24.3 million one year ago. Thus, GPU net income after extraordinary items was $26.4 million for the 12 months ending November 30, 1982, contrasted with a negative $6.7 million only one year ago.

The major extraordinary item for 1981 was a $27-million write-off of the abandoned Forked River nuclear plant, while the two major extraordinary items in 1982 were the write-off of the excess of GPU's investment in its subsidiaries over their related net assets—a negative $30.1 million—and reversal of depreciation on TMI-2 for GPU subsidiaries Metropolitan Edison (Met Ed) and Pennsylvania Electric (Penelec)—+ $18.6 million.

Earnings per share (after extraordinary items) was $ .43 for the 12 months ending November, 1982, compared to a negative $ .11 for the same period in 1981.

GPU chairman and chief executive officer William G. Kuhns said that although earnings continue to be impaired by the fact that both TMI units have not been part of the rate base since the accident, actual short term debt for the GPU system currently is less than it was at the time of the accident.

GPU said it and agents for the consortium of banks participating in the revolving credit agreement had agreed on terms to extend the accord through 1983. The previous RCA expired on December 31, 1982.

Credit available to the GPU system under the new agreement will remain at the $200 million level, with a sublimit of $125 million initially available. The new sublimit is lower than the previous one—by $25 million.

"While GPU's cash position has improved substantially since the original RCA was implemented in 1979 after the Three Mile Island accident, some relatively small working capital loans will be necessary during 1983," Kuhns explained.

A GPU parent company debt of $36 million remained outstanding under the RCA/term loan accord that expired last year. That debt has become part of the new agreement and is expected to be repaid by mid-1983. Met Ed, Penelec, and the third GPU subsidiary Jersey Central Power & Light, as individual subsidiary companies, currently have no bank debt outstanding.

"This differs dramatically from the period following the TMI accident when short term debt peaked at $323 million in June of 1980," Kuhns said.

"In addition," he said, "Met Ed and Penelec expect to retire their bond obligations that mature in the spring of 1983 out of funds now on hand for that purpose plus funds to be generated internally during the intervening period."

In related news, the U.S. District Court for the Eastern District of Pennsylvania has denied a motion by the United States to dismiss a suit filed by GPU companies in December, 1981, against the government. Basing its claim on the Federal Torts Claims Act, GPU is seeking to recover damages resulting from the 1979 accident.

GPU argues that the Nuclear Regulatory Commission was negligent when it failed to inform the company and other electric utilities of information it had on a previous nuclear plant incident that GPU says could have prevented the TMI accident.

Although the district court refused to dismiss the GPU suit, it did allow for the consideration of its decision by the Court of Appeals for the Third Circuit. The district court also stayed further lower level proceedings.

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THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

lear participants, fearing imprudence rges by PUC's, begin to speak out

Silence is becoming less golden than nuclear expenditures

Dan Utroska
Associate Editor

The announcement last month by New England Electric System that it wants to back out of its participation in the Seabrook nuclear plant is the latest in a series of developments that reveal the growing managerial responsibilities of electric companies that cooperate in the construction of nuclear power plants.

At a meeting of securities analysts in Chicago, New England Electric System chairman Guy W. Nichols said the system's subsidiary, New England Power, had decided to publicly announce its plan to end participation in Seabrook in order to demonstrate its corporate awareness of the controversial circumstances surrounding construction of the plant.

In addition, NFP sees its public declaration as possibly insulating it against negative rate sanctions should the plant later be cancelled or experience cost overruns that are unacceptable to state and federal regulatory bodies.

This declaration by New England Power is significant in what it implies for other similarly situated companies in the electric utility industry. First, the announcement draws its substance from the unhappy experience of numerous state and federally regulated utilities who were participants in now-cancelled nuclear projects and who were disallowed recovery of invested capital because they were adjudged to have acted imprudently, even though full construction control was invested by contract in a principal, or "lead" utility.

Zimmer participants question accords-p.53

Second, the announcement exemplifies what could become a growing divisiveness on the part of participant utilities, as nuclear projects become increasingly expensive during a time of falling electricity demand. Interestingly, utility participants in the beleaguered Zimmer nuclear plant have announced they are seeking "arbitration" with Cincinnati Gas & Electric Company over elements in their ownership contracts, but are simultaneously attempting to present a united front by withholding their grievances from public view (see story, this issue, page 53).

Third, attempts by nuclear participants to reposition themselves with respect to their power supply contracts with constructing utilities—either by closed-door negotiations or through public declarations that seek to mothball or cancel projects—is surely to have an impact on contracts not yet written. With currently large reserve margins and the growing costs of nuclear power, utilities building nuclear plants often are searching for new partners. The public renegotiation of existing partnership agreements—if these do not entirely scare away potential new entrants—are at least likely to result in contracts with larger escape hatches for the smaller, historically less powerful participating utilities in case things go sour.

NEP wants out

According to New England Electric System's Nichols, NEP has invested more than $40 million in Seabrook-2, and adding allowance for funds used during construction, the investment approaches $60 million.

"We think it would be in the best interests of our customers if unit 2 were to be cancelled," said Nichols.

NEP first announced that it would seek a buyer for its share of the plant, but when asked by utility analysts in

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Man of Year accepts award

Southern California Edison Co. Chairman and Chief Executive Officer William R. Gould (l.) accepts the 1983 Electric Industry Man of the Year Award from EL&P Editor-in-Chief Robert A. Lincicome (r.) at the American Power Conference in Chicago.

Three utilities' '82 achievements gain Edison Medal nominations

WASHINGTON, D.C.—A New England utility and two from the west coast have been selected as the 1982 nominees for the Edison Electric Institute's coveted Edison Medal. The three investor-owned utility nominees are Central Vermont Public Service Corp., Puget Sound Power & Light Co. and Southern California Edison Co.

The three utilities were nominated for achievements in 1982 and have been invited to submit presentations documenting the accomplishments for which they were nominated. Presentation of the award, which consists of the medal, commemorative certificate and a contribution to the winning company's employee fund, will be made at the Edison Electric Institute's annual convention in Minneapolis, MN, June 6-8.

Citations for the three nominees are as follows:

"*Central Vermont Public Service Corp.*—For successful initiation and implementation in 1982 of a "partnership" relationship with its customers that by the end of that year had resulted in favorable ratings in customer surveys which exceeded average ratings of other electric utilities in the region (New England) and the nation. Specifically, a "Partners in Energy Conservation" program consisted of three facets: sale and installation of insulation jackets for water heaters saved customers about 10-million kWhs and $500,000; a mechanism for alerting customers via local media of the possibility of peak demand occurrences and the voluntary cooperation of the customers in reducing usage at such times enabled the company to keep its system peak below that of the previous year; and a "community demand management" program, enlisting the cooperative efforts of customers in discovering methods of minimizing energy demand and consumption, also contributed to successful avoidance of new demand peaks during the year, with attendant cost benefits to itself and its customers.

"*Puget Sound Power & Light Co.*—For furthering the concept of strategic corporate planning in partnership with its customers, which has allowed the company to improve its credibility and responsiveness to customer needs, and provide substantial, studied input to the Northwest Regional

Continued on page 8

California PUC expands rules to fund rate case intervenors

SAN FRANCISCO—Citing the increasing value of expert intervenor participation in complex ratemaking cases, the Public Utility Commission here has significantly broadened the rules under which participants would be compensated for their contributions.

The new compensation rules go beyond those that had been in effect before and that had been limited to provisions of the Public Utility Regulatory Policies Act (PURPA). Under PURPA, state regulators could award compensation to intervenors who made substantial contributions to decisions only in a limited range of electric utility proceedings.

According to Commissioner Victor Calvo, the new PUC participant compensation rules "are a key element in ensuring that there is full development of issues for the commission's consideration." Calvo said effective public participation is an essential

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Foreign Power Briefs

- **Spanish Atomic Forum** President Alfonso Alvarez Miranada sharply criticized Spain's Socialist government for its intention to reduce nuclear power by 7,500 MW by 1990. Miranada says the planned cuts would cause more unemployment and reduce industrial growth.

- **The Soviets** have commissioned their second 1,000 MW PWR at the South Ukrainian plant on the River South Bug. When completed, the plant will have four 1,000 MW units. The plant also will include hydroelectric and pumped storage stations. The electricity is being supplied locally and to USSR allies in Eastern Europe.

- **The Republic of Ireland** has the highest electricity prices in the world, according to a survey by National Utility Services. Power in Ireland costs 7.42 cents per kilowatt-hour compared to 5.85 cents in the United States and 3.21 cents in Canada. Australia, which charges 4.36 cents per kilowatt-hour, had the highest annual increase for 1981-82 with a 26.6 percent rise.

- **Ontario Hydro** reports that the final M*A*S*H episode in February boosted CBS ratings and the utility's electricity demand. When the program started, energy demand increased 15,000 to 20,000-kW (equal to about 60,000 television sets). The utility said that throughout the episode there was a pattern of small spurts and drops in energy demand. A Hydro spokesman said the changes could have been caused by viewers turning on lights and opening refrigerator doors during commercials.

- **The International Atomic Energy Agency** says 294 nuclear plants were operating in 25 countries at the end of 1982. They generated more than eight percent of the world's electricity. The agency estimates that by 1985, 17 percent of the world's electricity should be generated by nuclear power.

- **Listowel, Ireland** will be getting a new steam generating plant. Kerry Co-op selected the Battelle Multi-Solid Fluidized Bed technology for the facility. Kerry, a large processor of milk products, will burn coal and coal-peat mixtures in the boiler. It is expected to be installed in 1984 and will replace an existing oil-burning system. The system will be designed and built by Foster Wheeler Power Products Limited of London.

- **Soviet electricity** output rose three percent last year to a total of 1,366 TWh. Almost 9,500 MW of new capacity was added in 1982 adding up to a total of 287,000 MW.

- **European Economic Community** (EEC) electric consumption dropped last year for the first time since 1975. The EEC Commission in Brussels said 1982 consumption fell 0.5 percent from 1981 to 1,211 billion kWh. Britain recorded the biggest drop (-2%). Consumption also was down in West Germany, Holland and Belgium. About half of the Common Market's nuclear production was produced by France (103.1 billion kWh).

- **Kenya** will expand the first geothermal project in Africa with the addition of a third 15 MW steam turbine generator. The Olkaria geothermal station, northwest of Nairobi, already has two 15 MW generators in full operation.

- **The Institute of Nuclear Power Operations** has formed a new international division that will coordinate INPO activities with international participants from the 13 countries affiliated with the organization.

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EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (••). All readers receive EL&P's industry news section.

Emphasis on new plant construction is 'stupid,' key congressman charges

WASHINGTON, D.C.—The unrelenting attention by the electric utility industry on the construction of new power plants to the exclusion of other lower cost alternatives has been severely criticized by a congressman influential in energy matters.

Charging that the industry has been "a very sluggish, unimaginative one" in its singular focus on new power plant building, Rep. Richard L. Ottinger (D NY) protested, "If, as all the studies that have been made indicate, the least cost option is to invest in conservation, load management, cogeneration, and renewable energy resources, rather than just building more central station power plants, ...then it seems to me just blindness and stupidity to continue to pursue the old path—the far more expensive path, the path to economic ruin—while ignoring the much more attractive options."

The congressman's remarks were published in an exclusive interview in the December/January issue of *Electric Ratemaking*, an Arlington, Virginia publication exploring trends on electricity planning, finance, economics, and pricing.

Ottinger believes that incentives are already in place that should stimulate serious examinations of alternatives to power plant construction but that these are thwarted by a "mind-set" that the business of utilities is to build new generating facilities, not to supply least cost energy services.

He notes that the industry has already been successful in killing the Department of Energy's Residential Conservation Service (RCS) program in the House Appropriations Committee, when it ought to instead have pursued this actively.

The democratic congressman also hit what he sees as mistaken policy changes currently being contemplated by DOE's Electricity Policy Project. "The whole focus of that effort is to facilitate the utilities being able to build more uneconomic plants," Ottinger said. "I think if they [DOE] succeed, and drive [up] the price of electricity still further, they will have bankrupted the utilities faster than they would otherwise..."

Ottinger, who is chairman of the House Subcommittee on Energy, Conservation, and Power, and a member of the House Committee on Science and Technology, said that the solution to utilities' financial problems does not lie in additional building of uneconomic plants, but will be found in electric companies working to satisfy increasing energy needs at the least expensive price.

"To tell the consumers—look, your financial markets cannot do this at a decent price, so you...have to build these uneconomic plants—is outrageous. Absolutely outrageous," *Electric Ratemaking* quotes Ottinger as saying. "I don't think Congress will sit still for that."

Nuclear option hit

The magazine also reports that Ottinger was critical of the way nuclear power has developed in the U.S. It is not that there have been regulatory delays caused by the licensing procedures used by the Nuclear Regulatory Commission, he argues, but that nuclear utilities have tried to sidestep safety considerations in construction and have sought to "build the plants however we...please."

"Not only is that intolerable from a safety standpoint, but it's...stupid," Ottinger said.

He contends that nuclear power is so complex and provides so many chances for human error in plant operation that unanticipated and costly shutdowns are not only likely but work to make these plants uneconomical. This means that nuclear power is advancing more for "theological" than market-based reasons, Ottinger says.

The Congressman concedes that some companies are pursuing conservation, alternative energy sources, and least-cost approaches, and that it is unfair to characterize all electric companies generally. He also admits that the industry increasingly has been examining these less traditional approaches to serving their customers.

"But," Ottinger concludes, "I go to the EEI [Edison Electric Institute], and there is a substantial body of opinion that is still frozen in the mud; that thinks conservation, cogeneration and renewables are a side show. They say—well, we'll give lip service to them, then let's talk about the really serious business which is how do we raise enough money to build more plants."

Study finds utility management good

WASHINGTON, D.C.—An evaluation of utility management audits shows "generally sound management practices," including "good management teams, sound business practices and appropriate priorities."

The report, prepared by Quadrex Corp. for the Edison Electric Institute, covered independent management audits of 47 electric utilities and found that 58 percent of the companies received "highly positive" reviews. Of the remaining utilities, 32 percent were given reviews classified as "positive," with "some form of qualification or condition placed on the remarks."

High quality

"The audits clearly demonstrate that the overall quality of utility management is high, given the economic, financial and regulatory constraints on the industry," said Douglas C. Bauer, senior V.P. at EEI. "They show that on the whole, utility management is technically competent, cost-conscious, and far-sighted in its planning—and that external factors greatly handicap what could otherwise be exemplary operations."

Performed between 1974 and 1982, the audits covered all aspects of company operations, business practices, financial management techniques and administrative procedures. They were conducted by independent consultants retained by state regulatory commissions, or by staff experts trained in performing audits.

"Auditors found that, although the electric utility industry has experienced financial difficulties over the past eight to ten years, many of the problems encountered by management were induced from the outside," the report stated.

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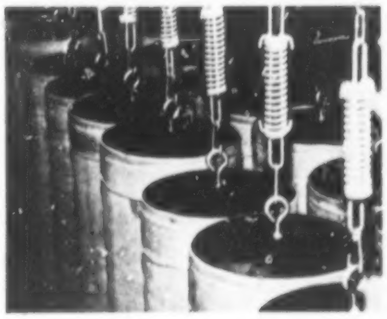
Filters rated reliable, cheaper to operate than precipitators, says EPRI survey report

BAGHOUSE O&M COSTS LOWER THAN ESP'S

	Labor & Mat'l	Power	Total
ESP	0.103	0.238	0.341
ESP Ash Removal	0.113	NA	0.113
ESP Total	0.216	0.238	0.454
Baghouse O&M	0.087	0.19	0.277
Baghouse Ash Removal	0.020	NA	0.020
Baghouse Total	0.107	0.19	0.297

Source: "1983 Update, Operating History and Current Status of Fabric Filters in the Utility Industry," by Walter Piulle, Robert Carr, EPRI, and Peter Goldbrunner, Burns & Roe, Inc. Second Conference on Fabric Filter Technology for Coal-Fired Power Plants, March, 1983.



DENVER—Operating and maintenance costs for baghouse filters on utility power plants are one-third less than costs for electrostatic precipitators, according to a paper presented at the recent Second Conference on Fabric Filter Technology for Coal-Fired Power Plants here. The paper, one of the first comprehensive reports on filter performance and operating costs, was prepared by Walter Piulle and Robert Carr of the Electric Power Research Institute and Peter Goldbrunner of Burns & Roe. It reported results of an EPRI-sponsored survey of utilities that are operating or building filters.

On the key question of bag life the survey found that installations fall into two categories: 55 percent of the baghouses are still using original bags with low failure rates and the rest are having problems, with some installations forced to replace all or most of the bags as soon as six months after startup.

In the category with good bag experience, average operating time is 2.5 years and average annual failure rate is one percent. In the other group, no simple explanation was offered for the poor experience: "The short bag life was attributed to either site-specific damage to the bags or manufacturing defects." The bag data was based on responses from 35 operating units.

84 operating units

The report says there are now 84 filters in operation on 10,813 MW of generating capacity and another 32 under construction or on order for 10,108 MW. The first filters on large power plants in the U.S. date back to 1973. Use of filters has increased rapidly since the strict, 1979 EPA particulate emission limits were adopted. Filters are at coal-fired units as large as 800 MW. Eleven stations use them with SO_2 scrubbers.

Sulfur content of the coal burned in these units ranges from 0.4 to 5 percent, with the average below one percent—an area that has posed problems for some electrostatic precipitators. The survey found that actual coal characteristics varied considerably from design specifications, "...yet these variations do not seem to affect baghouse performance or operation adversely."

Overall, says the paper, "A majority of the operating units perform quite well and satisfy emission control requirements." (Four "problem installations" were described: Kaw units 1 and 2, Clay Boswell, and Longworth unit 1.)

Some of the performance findings, based on detailed responses from 23 operating installations, a followup questionnaire, and on-site visits to nine units:

- The "typical" removal efficiency is in excess of 99.5 percent, ranging from 99.97 percent (Lon Wright unit 7 and Columbia 4 and 5) to 98.4 percent (Kaw.) The filters were designed to remove from 99 to 99.9 percent.
- Flange-to-flange pressure drop in the reverse-gas cleaning installations (71 of 84) ranged from 3.5 to 7 inches water (gauge) in the reporting units, with the exception of the Kaw unit, at 12 in. The pulse-jet and shake-deflate types reported pressure drops of 8-12 in. The paper says that many of the units reporting pressure drops above the design level also reported problems with bag life.
- Boiler availability was reported to be largely unaffected by baghouse operation. Seven exceptions to "generally good reliability" were noted: Monticello 1 and 2, H. R. Milner, Clay Boswell 1 and 2, Arapahoe 3 (the solution to problems here were reported in the April issue of *EL&P*, page 23) and Cromby 1.

The report summarized the major causes of operating problems: mechanical problems in the baghouse were caused by flow valves and valve operators at 54 percent of the responding installations, reverse-gas fan bearings at 31 percent, and ash distribution problems at 27 percent.

Bag-life problems

As mentioned above, the paper reported no common cause of bag failures: "Most installations reporting replace fewer than six bags each month although there are exceptions. Monticello (shake-deflate) reports replacing several bags daily for the last four years; Cromby (pulse-jet) completely rebagged their units (900 bags) after less than one year of operation; Longworth (pulse-jet) has rebagged five times in three years; Clark (reverse-gas) replaces about 400 bags each year...At Monticello...the original silicon-graphite-coated fiberglass bags stretched and were replaced within six months with Teflon-coated fiberglass bags which lasted approximately one year. At Clay Boswell...400 bag failures occurred in the first year; the cause of failure was inadequate tension that allowed the bags to droop, causing creases and wear points. At Cromby unit 1...12 percent of the bags developed tears at support cage circumferential stiffeners, and the unit was completely rebagged after less than one year of operation."

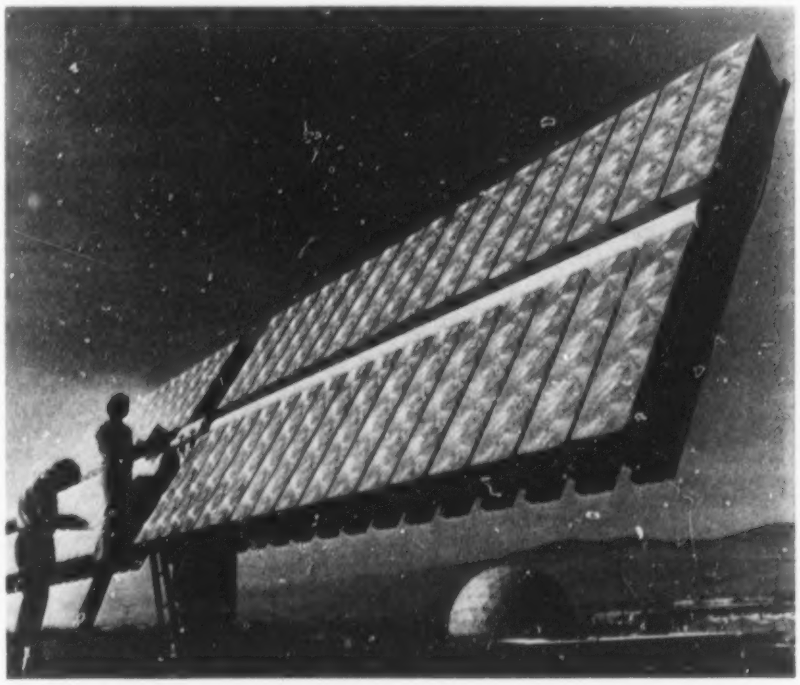
Most bag replacements were done with 10-oz-per-yd fiberglass with a 10-percent-by-weight Teflon coating. Exceptions are proprietary, acid-resistant coatings used at Cherokee and Nulca and silicon-graphite at Bullock.

Despite the problems at some installations, most, according to the paper, replace fewer than six bags monthly. Replacement is reported to be handled without much problem: the typical 36-ft long, 12-inch diameter bag change-out time is reported to be 15 to 20 minutes for two men.

More data needed

The paper asks for ideas from utilities with filters for beefing up the data collection effort which is continuing through 1983. The authors note that the O&M cost data, for example, is based on only 14 reporting filter installations.

PG&E connects new solar unit



This photovoltaic installation overlooking Pacific Gas & Electric's department of engineering research in San Ramon, CA has a tracking system that keeps the lenses pointed at the sun. The demonstration unit is the first of its kind to be connected to PG&E's grid.

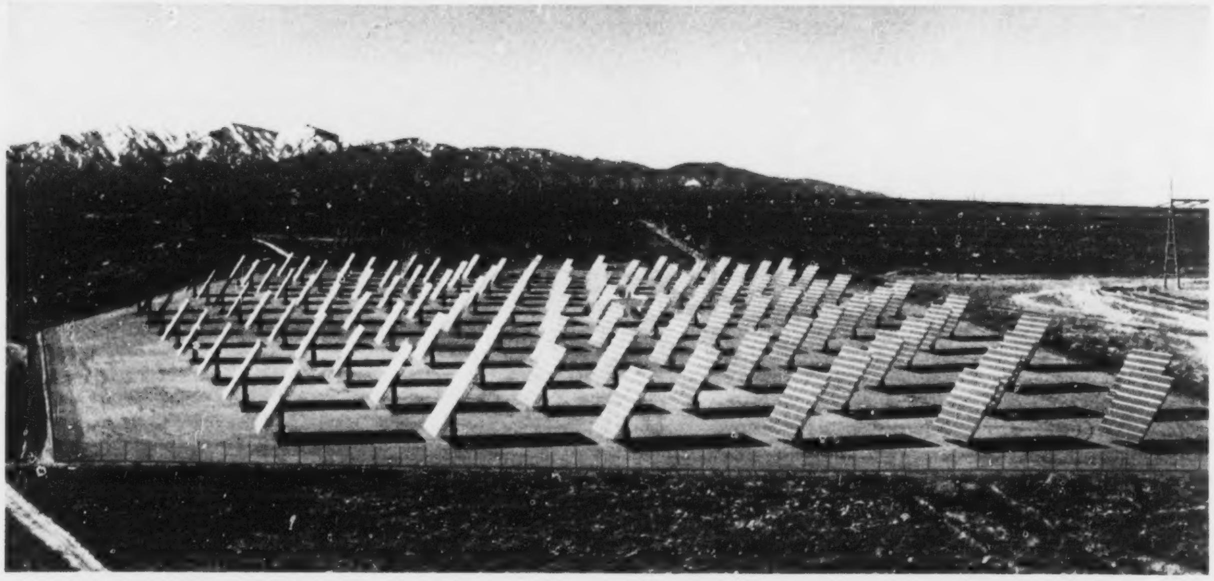
DOE checking results from light-water breeder

ARGONNE, IL—A multi-laboratory effort to investigate the success of an attempt to breed nuclear fuel in a light-water reactor is underway, reports Argonne National Laboratory, one of the participants.

Five years ago DOE's Shippingport nuclear reactor (the first to supply commercial electricity to a utility company) was loaded with an unusual fuel—uranium-233 and pellets of thorium oxide. The object of the experiment was to convert the thorium into U-233 so that the spent fuel contains more U-233 than was consumed while the reactor operated.

Argonne explains that the experiment is important because it will demonstrate whether existing light-water reactors can be operated as breeders and because there is 15 times more thorium in the earth's crust than U-238, the 'fertile' material converted into nuclear fuel in the uranium-plutonium cycle used in the liquid-metal fast breeder reactor.

The Shippingport reactor was shut down last October and Westinghouse's Bettis Atomic Laboratory is currently removing the 17,000 fuel rods from the core. They will be shipped to DOE facilities in Idaho and Argonne, IL for analysis.



The first megawatt-scale photovoltaic solar energy plant was built in the Southern California desert by Arco Solar Inc. and is supplying electricity to Southern California Edison.

Oil company brings photovoltaic solar power to the electric utility industry in California

Robert Smock
Managing Editor

If photovoltaic solar power doesn't make it, it won't be the fault of Arco Solar, Inc. This subsidiary of the Atlantic Richfield oil company is almost singlehandedly bringing commercial-scale photovoltaic energy production to the electric utility industry. Taking advantage of generous tax credits for alternative energy sources in California, Arco has:

- Installed, and is operating, a 1-MW photovoltaic solar energy facility that is providing electricity for Southern California Edison;
- Sold a 1-MW photovoltaic installation to Sacramento Municipal Utility District at the breakthrough module price of $5.60 a peak watt;
- Announced plans to build and operate a 6-MW facility to provide electricity for Pacific Gas & Electric.

Describing the trouble-free, nine-month construction project at the operating 1-MW plant, Arco Solar vice president John Cheatham talks about the "simplicity and elegance of photovoltaic technology."

He acknowledges that it is not yet cost-competitive with conventional energy sources, saying, "I know costs may be high now but forget that, the future looks good." Lending weight to his optimism is the rapid pace of technology development over the past five years in terms of installation size scale-up and cost reduction.

Technology development

Prior to about five years ago photovoltaic solar energy was a high-priced oddity relegated to applications such as space vehicles or remote desert sites where electricity cost wasn't important. These were about the only applications that could take advantage of the "simplicity and elegance" of the photovoltaic effect—light shining on a properly fabricated semiconductor material can produce an electric current with, literally, no moving parts necessary. The problem was that a properly fabricated semiconductor material—typically slices of single-crystal pure silicon—was prohibitively expensive for commercial energy applications.

That perception changed in the late 70's, due both to promising research results and a federal administration that encouraged the development of new energy technology. The U.S. Dept. of Energy launched a formal photovoltaic energy program with annual funding about $150 million. A most unusual aspect of this program was a set of specific price targets: DOE said its goal was to reduce the cost of a photovoltaic module from the prevailing level of about $20 a watt to $2.80 a watt by 1983, 70 cents a watt by 1987, and 40 cents by 1990. The 1990 target was felt to be the threshold for commercial competitiveness.

The amazing thing is, the prices are falling and they're falling almost on schedule. Despite a cut in federal funding to the $50 million a year level, the technology and the industry are rapidly advancing.

However, until Arco Solar stepped forward last year, most of the photovoltaic installations were kW-scale facilities at remote sites or at wealthy peoples' residences, or were taxpayer-subsidized projects.

The only large-scale, bulk solar power projects underway were government-subsidized solar-thermal installations such as Southern California Edison's 10-MW Solar One. Utilities were looking at solar-generated steam from power-tower-type facilities as a possible way to retrofit existing fossil-fueled stations. Photovoltaics was considered a possibility for the 21st century, given a technological breakthrough.

Arco's installations

In early 1982 Arco Solar broke the orderly pattern of photovoltaic development by announcing that it was going to build a 1-MW photovoltaic installation in the Southern California desert next to a Southern California Edison substation. The energy would be sold to the utility at avoided cost. The facility was more than twice the size of the largest photovoltaic plant under development at the time and, more interestingly, there was no government money involved.

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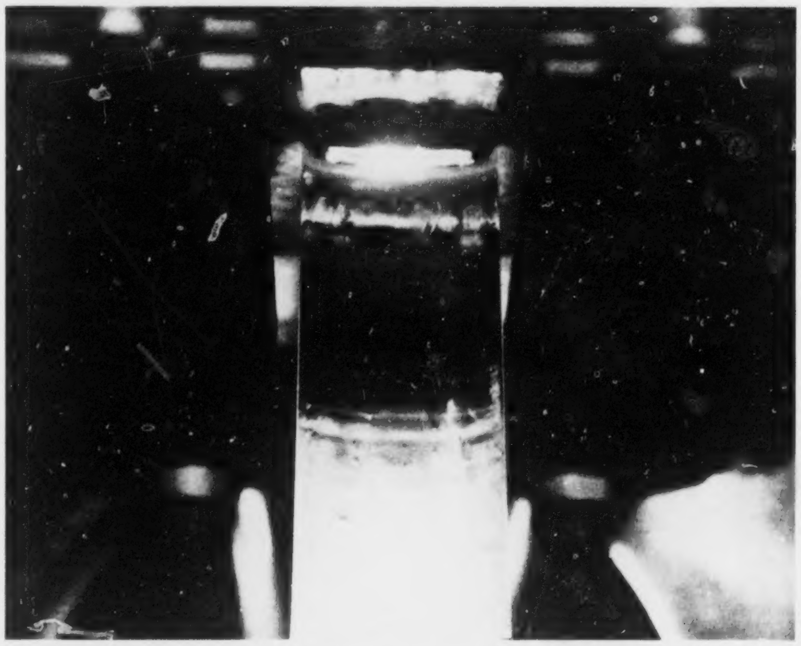

A technological breakthrough is needed to make photovoltaic energy cost competitive, such as the development of low-cost, "thin films." Shown is a wafer-thin silicon ribbon produced by Arthur D. Little, Inc.

UTILITY PHOTOVOLTAIC PROJECTS
(> 20 kW)

1. **Arizona Public Service**
   225-kW installation at Phoenix airport, operational in July 1982.
2. **El Paso Electric**
   175-kW installation at utility Newman power station, operational June 1981.
3. **Kauai Electric (Hawaii)**
   70-kW array on a hospital, startup January 1982.
4. **Lea County Electric Coop (New Mexico)**
   100-kW array at a shopping center, operational March 1981.
5. **New England Electric**
   100-kW system on roof of high school, operational in March 1981.
6. **Oklahoma Gas & Electric**
   125-kW array at civic center building, operational February 1982.
7. **Pacific Gas & Electric**
   6 MW installation to be built, owned and operated by Arco Solar.
8. **Sacramento Municipal Utility District**
   1 MW installation planned for 1984 operation.
9. **Southern California Edison**
   1 MW system owned and operated by Arco Solar, operational in December 1982.
10. **Texas Power & Light**
   25-kW (+140 kW of process heat) installation at Dallas-Fort Worth Airport, operational in December 1981.

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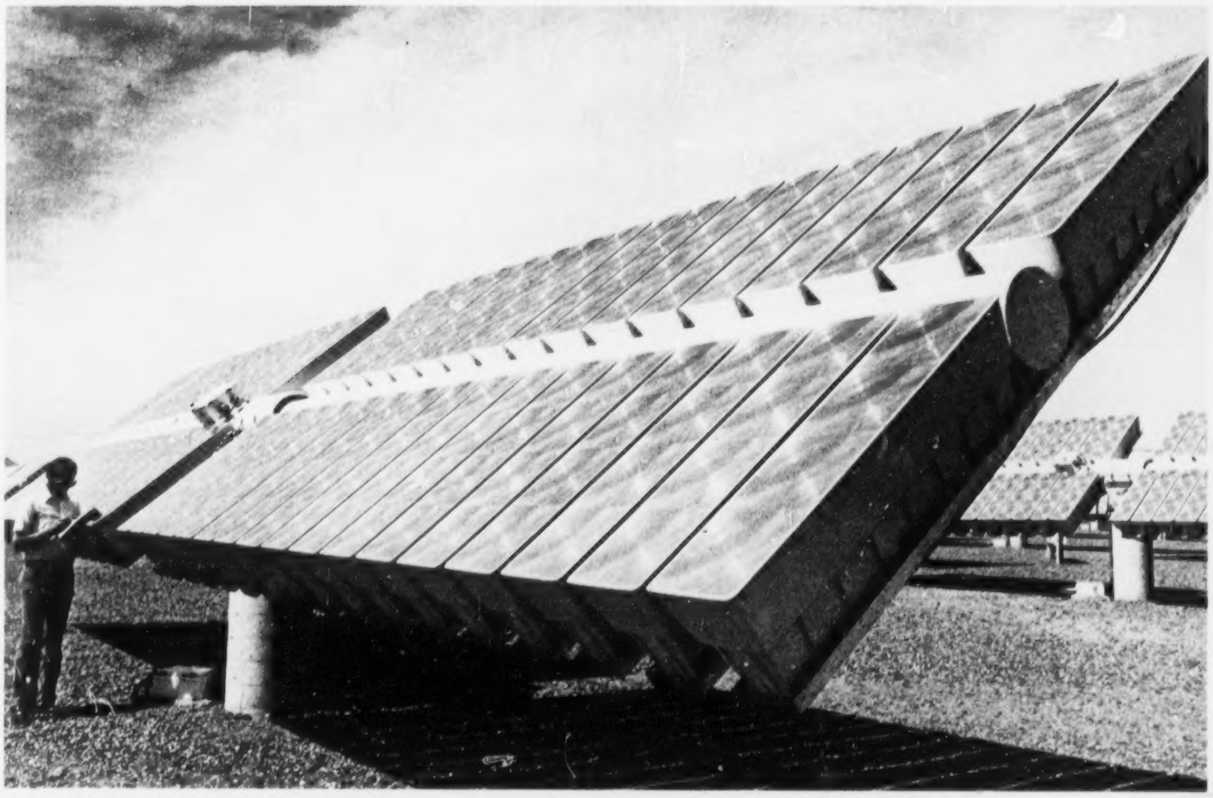
The "simplicity and elegance" of photovoltaic solar energy make it a favorite for potential large-scale electricity generation.



Typical of the DOE-sponsored utility photovoltaic projects is the $4 million, 225-kW installation in Phoenix by Martin Marietta that is operated by Arizona Public Service Co.

Arco says the capital cost is proprietary, but company vice president John Cheatham reported at the recent Energy Technology Conference that the installed cost of a 1-MW Arco photovoltaic plant is $11 to $12 million. He said that tax credits (that in California add up to more than one-third of the cost of such a facility) are necessary, that the Southern California Edison installation would not have been built without them. "It is unfortunate," said Cheatham, "that just at the point when these tax credits are beginning to demonstrate their fundamental efficacy and efficiency for large-scale utility projects, that they are being brought into question by policy makers."

Even with tax credits photovoltaic solar energy is clearly not competitive yet with conventional electricity. Cheatham said the California facility will produce 3 million kWh annually. A hypothetical avoided cost of 10 cents a kWh won't generate much cash flow for a $12 million capital investment. But Arco is obviously looking to the future.

So is Southern California Edison. Said utility executive William Gould at the facility's dedication in February: "This photovoltaic plant in many respects approaches the ideal. In addition to using abundant solar radiation as fuel, the plant does not produce any waste water, air emissions or thermal by-products. The plant does not require fresh water for cooling, a factor so important to us in the west. Also, this facility has been built in record time, from April 1, 1982, when we signed the power purchase agreement with Arco Solar to its connection to our grid last December 1. The plant is elegantly simple in its construction, operation, and, I would estimate, in its long-term maintenance."

The 1-MW plant occupies 20 acres, but could have been squeezed onto 16, according to Arco's Cheatham. The plant will have the first large-scale application of trackers which tilt the panels to face the sun throughout the day. This boosts the plant's expected annual capacity factor to 35 percent from the 20 percent typical of fixed-angle photovoltaic systems (in sunny climates.) Cheatham claims the plant will produce at near-full output all day long, coming up quickly in the morning and staying there.

The site is unmanned. Operating costs, chiefly for cleaning, are expected to be low, says the official. Module life is estimated by Arco to be 20 years.

Low-cost bid

The next development for Arco Solar was the announcement by Sacramento Municipal Utility District that it had awarded the firm a contract to supply 1.2-MW (DC) of photovoltaic modules at the suprisingly low price of $6.7 million, or $5.60 a watt. A roughly equal amount for the balance-of-system and installation brings the total cost to about $12 million, according to SMUD. That's the lowest price per peak watt of any major photovoltaic purchase to date, says the utility.

It will be the first large photovoltaic facility owned and operated by a utility but, unlike the Arco facility in Southern California, most of the funding will come from government agencies. The federal government will provide $6.8 million, the state $2 million, and SMUD $3.2 million.

This is to be the first step in a proposed 100-MW photovoltaic power facility SMUD plans to build next to its Ranch Seco nuclear plant. It is scheduled to be completed in 1984.

The most recent development was the late-March announcement that Arco would build and operate a 16-MW installation to produce electricity for Pacific Gas & Electric. The first phase of the project, to be financed by Arco, will use 4 MW of photovoltaic panels with reflectors designed to boost output to 6 MW. Operation is planned for March 1984. Arco said it is seeking financing for a second phase totaling 10 MW.

Photovoltaic solar now joins wind power in California as the only large-scale, exotic energy sources getting support from private investors.

COMPANIES WITH SHIPMENTS OVER 100 kW*

U.S.	Arco Solar Products
	Photowatt International
	Martin Marietta
	Solarex
	Solar Power
	Solec International
	Solenergy
	United Energy Corporation
Japan	Fuji Electric Co.
	Japan Solar Energy
	Sanyo Electric
	Sharp
France	France Photon
	SFP (Photowatt SA)
Germany	AEG Telefunken

*In total, 108 companies worldwide manufacture modules.

MODULE SHIPMENTS

Geographic breakdown Year	1980	1981	1982
World	3.3 MW	5.5 MW	8.4 MW
U.S.	2.5 MW	3.5 MW	4.9 MW
U.S. market share	76%	84%	58%

Source: Photovoltaic Energy Div., Office of Solar Electric Technologies, Dept. of Energy.

New material needed

Dramatic and startling as these developments are, they still do not make photovoltaic energy economically competitive with conventional electricity. Robert Annan, director of DOE's photovoltaic energy division, says that the threshold price for commercial competitiveness is about $2.50 a watt, total system cost. "We think the existing technology will get us there," he says, "but we'll need a cheaper material."

Annan says the R&D on the material most used now—single crystal silicon—is being phased down by DOE. The most promising new method for achieving the needed cost breakthrough, in Annan's opinion, is the use of thin films of, possibly, amorphous silicon. "That's where we're putting all the chips," he says. Single crystal silicon can produce cells 150 microns thick with an equal amount lost in the sawing process, he explains. It's possible that films of amorphous silicon can be produced that are only 10 microns thick. Since the photovoltaic effect occurs only at the surface of the semiconductor, the potential for materials savings, and cost savings, is obvious.

Annan says that U.S. R&D work on amorphous silicon, thin-film technology is being handled by the Solar Energy Research Institute in Colorado. The official is confident this work, or progress in some other area, will lead to achieving the commercial cost target in the near future, perhaps as soon as 1985 or 1986.

New perception of photovoltaic

The best example of the new utility perception of photovoltaics is probably the paper co-authored by PSE&G and RCA for the recent winter meeting of IEEE's Power Engineering Society. The paper concluded that photovoltaic energy could be valuable to an electric utility on a fairly large scale, despite its intermittent, relatively unreliable nature.

The authors compared photovoltaic capacity to intermediate-load gas turbine capacity in a hypothetical expansion plan for PSE&G and found that the solar technology would be competitive at a capital cost (in 1982 dollars) of $1100 to $1350 per kW. Penetration levels as high as 15 percent of peak load were found to be feasible. A companion paper by RCA, which is one of the leaders in amorphous silicon development, presented a conceptual design of a 50-MW photovoltaic power plant.

In summary, it's far from certain that photovoltaic energy is going to meet its cost targets, but the huge momentum the technology has built up indicates it may be the first of new, exotic, renewable energy technologies to become economically viable.

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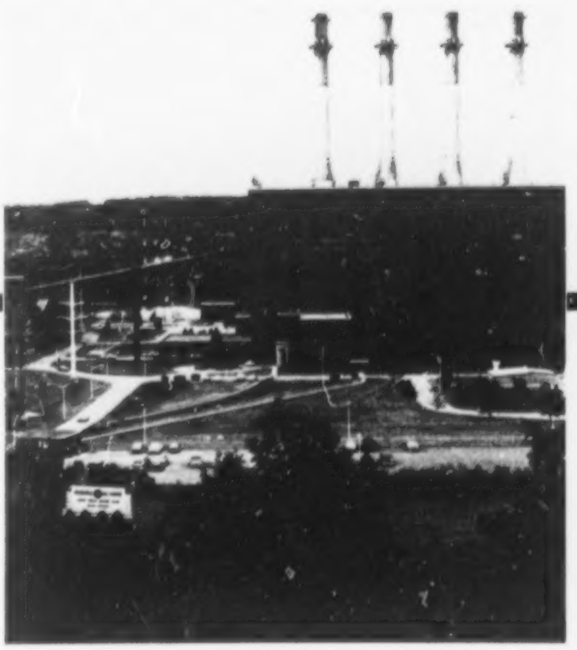
Typical of the eastern U.S. conversions that have dominated the trend so far is the planned switch to coal at Niagara Mohawk's 400-MW, four-unit Albany station. The units burned coal until 1971 when they were switched to oil for environmental purposes. Now fuel cost differences justify the $200 million capital cost of switching back to coal. (Photo courtesy of Fluor Corp.)



DOE's 'olive branch' approach to utility coal conversions is working

Robert Smock
Managing Editor

The best thing that's happened to encourage the utility oil-to-coal conversion trend, aside from increasing oil prices, is the change in policy at the U.S. Dept. of Energy. Gone is the club. Out is the olive branch.

In the minds of many managers at oil- and gas-burning utilities DOE is still associated with "mandatory conversion orders." Bureaucrats at DOE are assumed to have a "costs-be-damned, cram-conversion-down-their-throats" attitude. Indeed, that was the tone of the original federal legislation (ESECA) passed in the wake of the Arab oil boycott in 1973 to discourage the use of imported oil and the law (FUA) passed in 1978 after natural gas supply problems and intended to force utilities completely away from gas fuel by 1990. Utilities and federal regulators were adversaries and conversion lagged.

A new climate

The situation is completely different now, says Bob Davies, chief of the Fuels Conversion Division of the Office of Fuels Programs in DOE's Economic Regulatory Administration, and he would like the word to get out to the utility industry. DOE's coal conversion policy is to cooperate with utilities who voluntarily want to convert. It is not to force conversions on those who don't.

"There are many conversions that are economic but are not going forward," says the official, adding that he's afraid utilities aren't coming to DOE for help because they don't want to get involved with more regulators. Under the new rules and policies, however, working with DOE on conversions offers more benefits than risks, Davies feels.

The new, hassle-free attitude is partly due to an amendment attached to the federal Omnibus Budget Reconciliation Act (OBRA) passed in August 1981. Most utilities are aware that OBRA repealed the onerous 1990 off-gas provision of the Fuel Use Act, but the law also contained changes in coal-conversion regulations. Now, DOE conversion orders can only be issued to utilities that voluntarily apply for them and certify that the conversion is economically and technically feasible. Also, previous orders that aren't yet finalized can be allowed to expire. That means the initiative for a DOE order now lies with utilities who want to convert, not with Washington bureaucrats who think they should switch fuels.

A paper prepared by fuels conversion office staffers, Steven Frank and Loren Farrar, says, "Both the ESECA and FUA experiences, and congressional reports, argued for a program that emphasized voluntary conversions, a reduced Federal profile, and a cooperative stance to facilitate conversions, rather than an adversarial Federal role and regulatory process. The Fuels Conversion Division staff is directing its efforts to providing assistance in the conversion process for those facilities where utilities are seeking to convert voluntarily."

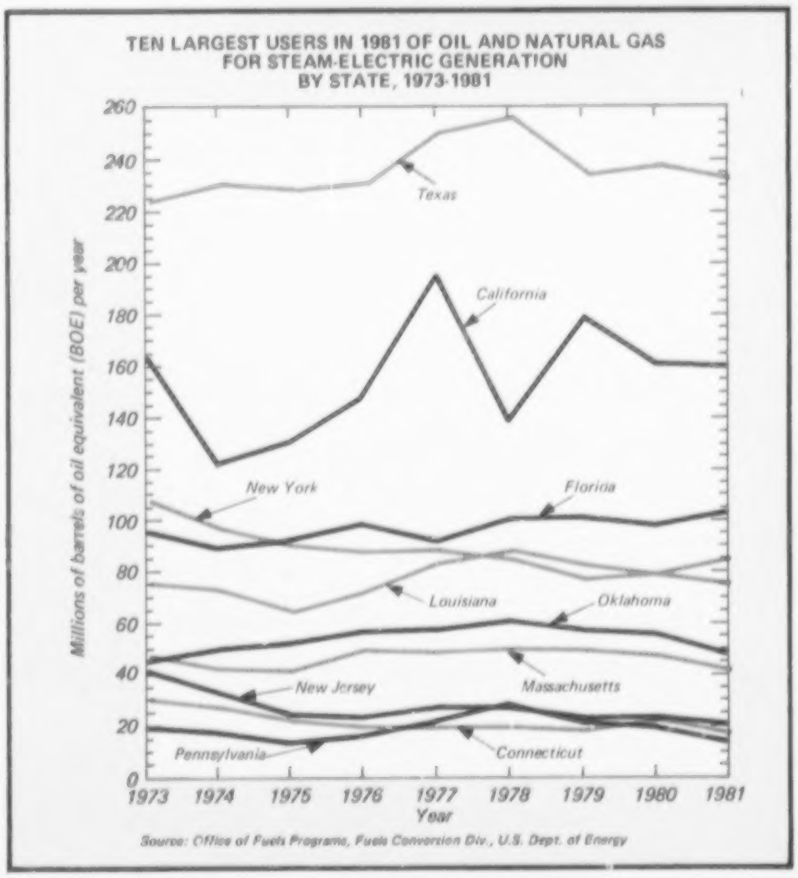
Scrubber exemption

The payoff to the utility from working with DOE is the ability to get an exemption from the federal New Source Performance Standards and Prevention of Significant Deterioration regulations—which simply means no sulfur dioxide scrubber will be required—and permission to burn coal in the facility while a new particulate emission control device is being built. It's possible to achieve the same results without going through DOE, but the fuels conversion staff feels that their power to grant legal exemptions gives utilities spending tens of millions of dollars on conversions a degree of certainty they can't otherwise get.

The only downside risk of working with DOE is the possibility of having to prepare an environmental impact statement to support the exemption order. Even that is not necessarily a disaster, says Steven Frank. He points out that the EIS for the trend-setting Tucson Gas & Electric Irvington conversion took only 6 months. "We were not on the critical path," he adds. (He admits that such swiftness might not be possible for an urban conversion.)

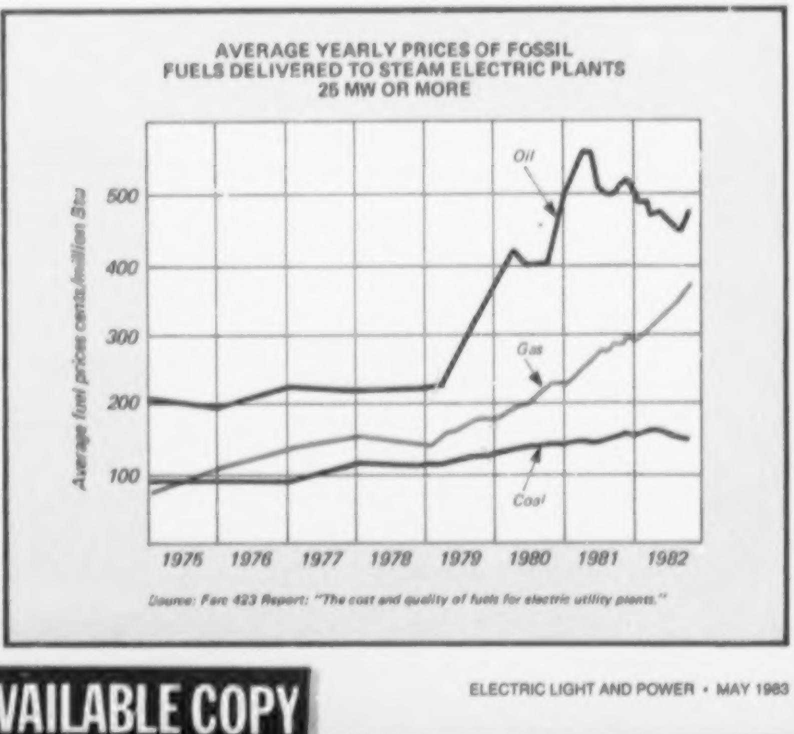
The fuels conversion staff report says that the Tucson conversion is an example of a case where scrubbers probably would have been required if the utility had not taken the DOE route. The conversion of the utility's gas-design capacity would have been considered a "major modification" by EPA, as defined by the Clean Air Act, which would have triggered application of the New Source Performance Standards (which require removal of 70-90 percent of SO_2 in the plant's stackgas.)

It should be pointed out that the DOE exemption applies only to federal regulations. State and local governments have the power to impose



TEN LARGEST USERS IN 1981 OF OIL AND NATURAL GAS FOR STEAM-ELECTRIC GENERATION BY STATE, 1973-1981

Source: Office of Fuels Programs, Fuels Conversion Div., U.S. Dept. of Energy



AVERAGE YEARLY PRICES OF FOSSIL FUELS DELIVERED TO STEAM ELECTRIC PLANTS 25 MW OR MORE

Source: Ferc 423 Report: "The cost and quality of fuels for electric utility plants."

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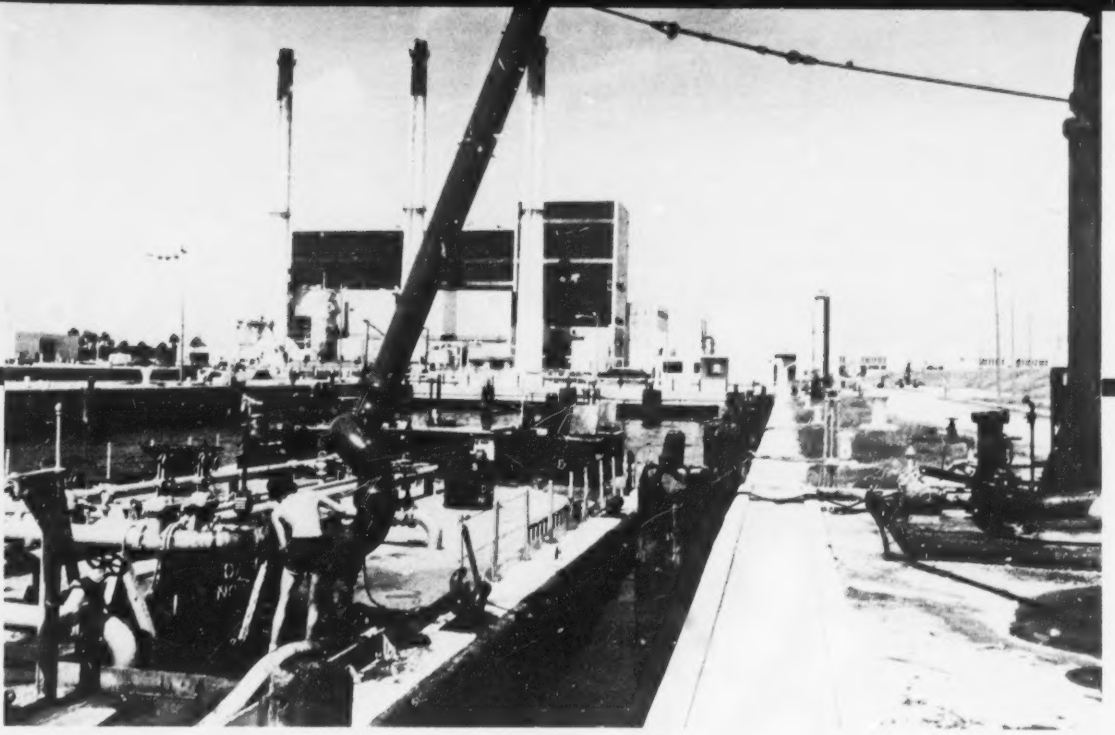

One of the more unusual conversions took place at Florida Power's Bartow unit 1. The plant is converting from oil to a mixture of coal and oil that is transported by barge from a preparation plant located across the bay. The fuel is handled and stored at the plant like oil.

DOE'S LIST OF POWERPLANT OIL-TO-COAL CONVERSIONS

Utility	Unit	MW
A. Converted[1]		
Alabama Electric Corp.	McWilliams 3	25
Ames Electric Municipal System	Ames 7	38
Atlantic City Electric	B.L. England 1,2	299
	Deepwater 7,8,9	121
Carolina Power & Light	Sutton 1,2,3	672
Central Tel. & Utilities	Clark 1,2	39
Colorado Springs Dept. of Public Utilities	Drake 5,6,7	257
Corn Belt Power	Wisdom 1	38
Florida Power Corp.	Crystal River 1,2	965
Fremont Dept. of Utilities	Wright 7	29
Independence City P & L	Blue Valley 1,2,3	115
Iowa Electric Light & Power	Sutherland 1,2,3	157
Iowa Power & Light	DesMoines 10,11	180
Iowa Public Service	Maynard 14	50
	Neal 1	147
Kansas City Board of Public Utilities	Kaw River 1,2,3	161
	Quindaro 1,2	340
Kansas City Power & Light	Tecumseh 9,10	238
	Lawrence 3,4,5	566
	Hawthorne 3,4,5	771
Nebraska Public Power Dist.	Sheldon 1,2	219
New England Power Co.	Brayton Pt. 1,2,3	1125
	Salem Harbor 1,2,3	334
Northeast Utilities	Mt. Tom 1	136
Potomac Electric Power	Morgantown 1,2	1252
Public Service Colorado	Camec 1,2	75
	Arapahoe 1,2,3,4	251
	Valmont 5	174
St. Joseph Light & Power	Lake Road 5,6	130
Savannah Electric & Power Co.	Port Wentworth 1,2,3	207
	Effingham 1	178
Springfield Utilities	James River 3,4	104
United Power Assn.	Elk River 1,2,3	46
Vineland Electric	Down 1	27
Virginia Electric & Power Co.	Chesterfield 4,5,6	1166
	Portsmouth 3,4	424
	Possum Pt. 4	239
Wisconsin Public Service	Weston 2	75
B. In the Active Process of Converting to Coal		
Baltimore Electric	Crane 1,2	399
	Brandon Shores 1,2	1220
Central Maine Power	Mascon 4-6	99
Consolidated Edison	Arthur Kill 20,30	826
	Ravenswood 30N,30S	928
Delmarva Power	Edgemoor 3,4	252
Florida Power Corp.	Bartow 2,3	367
	Bartow 1[2]	128
Medina Electric	Pearsall 1-3	66
Montaup Electric (Eastern Utilities)	Somerset 7,8	194
Orange & Rockland	Lovett 4,5	399
South Carolina Electric & Gas	Williams 1	633
Tampa Electric	Gannon 1-4	616
Tucson Electric	Irvington 1-4	240
United Illuminating	Bridgeport Harbor 3	250 of 400
Virginia Electric & Power	Portsmouth 1,2	226
	Chesterfield 3	113
	Possum Point 1,2	138
C. Giving Indications of Positive Plans and Expected to Convert		
Commonwealth Edison	Collins 4,5	1060
Florida Power & Light	Sanford 4,5	872
Long Island Lighting	Port Jefferson 3,4	375
Niagara Mohawk	Albany 1-4	400
Public Service Electric & Gas	Burlington 7	195
Public Service of New Hampshire	Schiller 4-6	150
Sierra Pacific	Fort Churchill 1,2	220
VEPCO	Yorktown 1,2	376
Western Massachusetts Electric (Northeast Utilities)	West Springfield 1-3	216
D. Considering and Studying Conversion Possibility		
Boston Edison	New Boston 1,2	738
	Mystic 4-6	469
Central Hudson	Danskammer 3,4	386
City of Gainesville	Deerhaven 1	83
City of Lakeland	McIntosh 1,2	230
City of Tallahassee	Hopkins 1,2	312
Connecticut Light & Power (Northeast Utilities)	Norwalk Harbor 1,2	326
	Devon 7,8	208
Florida Power & Light	Cape Canaveral 1,2	804
	Fort Meyers 2	402
	Manatee 1,2	1728
	Martin 1,2	1728
	Port Everglades 3,4	804
	Turkey Point 1,2	804
Jacksonville Electric	Northside 1-3	1160
Jersey Central	Sayreville 4,5	263
Long Island Lighting Co.	E.F. Barrett 1,2	374
Naragansett Electric (New England Power)	South Street	62
Philadelphia Electric	Cromby 2	230
Public Service Electric & Gas	Bergen 1,2	650

1. Includes 2500-3000 MW of conversions in the form of fuel switching only, not requiring significant changes in the physical plant.

2. Converting to coil-oil mixture.

Source: Office of Fuels Programs, Fuels Conversion Div., U.S. Dept. of Energy.

stricter regulations, including sulfur dioxide scrubbers, on conversions and DOE can not provide exemptions from these. However, to date, scrubbers have not been required.

"We recognize," says the DOE conversion staff report, "that few, if any, conversions have taken place without utility and state initiatives (sometimes after protracted negotiations), economic viability, and the ability to raise necessary capital. Gone is the potential club of a mandatory order and, in its place, is the understanding in the utility industry that they have greater control of the process. Gone is the protracted analytical and regulatory procedural aspects and in its place is a shortened version, more dependent on utility interaction and data."

Conversions continue

The DOE list of utility conversion projects shows that, despite the drop in oil prices over the past year, the number of projects is growing—perhaps as a result of the new federal policy. The official list shows that 27 utilities have now completed the conversion of 80 generating units, totaling 11,400 MW.

Conversion of an additional 11,000 MW of oil-burning capacity is either underway or definitely planned, and another 12,000 MW is under consideration. That adds up to 34,000 MW and that's close to the total of 40,000-50,000 MW of utility oil-burning capacity which is estimated to be readily convertible.

Conversion program manager Steven Frank points out that the list overstates the commitment slightly, because the "converted" category includes 2500 to 3000 MW of generating capacity that burned fluid fuels and coal prior to the conversion order and merely switched to 100-percent coal. But that leaves more than 8000 MW of power plants that have undergone a costly physical conversion in order to switch from oil to coal. And all the capacity in the other categories will require extensive physical changes to the power plants.

The 80 units that have converted now consume nearly 22 million tons of coal yearly which displaces 87 million

Continued on page 37

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Coal conversion . . . from page 33

barrels of oil. The nearly 100 units covered in the rest of the categories will, if eventually converted, consume more than twice that much coal. The DOE list covers just about all the easily converted coal-design and coal-capable capacity in the U.S.

It does not cover most of the oil- and natural-gas-burning capacity. Virtually all the utilities covered in the table (aside from the midwestern fuel-switchers) are on the east coast. The figure on oil and gas consumption by utility boilers, by state, shows the conversion trend has yet to tackle the big fluid-fuel users in Texas and California. In fact, the figure shows that of the ten largest users of oil and gas, five states showed increases—or at least no significant decreases—from 1973 to 1981.

The table indicates that there is still an enormous amount of utility generating capacity burning oil and gas untouched by the conversion trend. Most of this capacity was originally designed to burn oil or gas and will be difficult to convert. But, as Tucson Gas & Electric is showing, it is possible in at least some cases.

The price chart shows that the emphasis will probably shift in coming years to gas-burning plants. The oil-coal price gap has been high enough to justify large-scale conversions since 1980 and remains high enough even with the 1982 decline. The chart shows that the natural gas-coal price differential is now almost that high.

Commission influence

The pace of conversion in natural-gas-burning states will depend on actions by state commissions, just as it has in the oil-burning states. The enlightened commissions have learned that there is a large saving in fuel costs to be passed along to consumers if conversion can be accomplished. But, they've learned that utilities need an incentive, or at least fast recovery of the capital cost of conversion, to make it happen.

That's the pattern in two of the leading conversion states, Massachusetts and Florida, which have written 3-year conversion cost recovery rules into the rate structures. Now, other commissions are beginning to act.

For example, the New Hampshire commission encouraged conversion of 150-MW of oil-burning capacity at PS New Hampshire's Shiller station through a rate mechanism. The utility reported that its Energy Cost Recovery Mechanism would be increased by 0.22 cents for kWh for five years to recover the $73 million conversion cost. During that five-year period the fuel saving resulting from the conversion is expected to be $88 to $116 million, or 0.26 to 0.35 cents per kWh. Additional provisions are protection for consumers in the unlikely event that coal generation ends up costing more than oil and the potential for reward to utility shareowners if construction is completed ahead of schedule (1984) or if the units beat capacity-factor targets.

DOE funds development of slagging combustors

WASHINGTON—The Dept. of Energy announced that it will support technology development programs at eight companies aimed at designing slagging combustors to be retrofitted to oil-burning power plants to allow them to burn coal. The programs:

- TRW, Inc., Redondo Beach, Cal. wants to build and field test a small prototype of a slag-rejecting combustor that would partially burn the coal and remove the slag. The combustor would be connected to a boiler's existing burners where second-stage combustion would take place.
- Avco Everett Research Laboratory, Everett, Mass. would like to build and test a similar device.
- Science Applications Inc., La Jolla, Cal. has proposed a "wet oxidation" combustor for coal-water mixture oil substitutes that will reduce production of nitrogen oxides, sulfur oxides, and unburned particles.
- Energy and Environmental Research Corp., Irvine, Cal. wants to test the "vortex containment combustor" which was developed for an Air Force nuclear rocket program. It would reportedly be one-sixth the size of conventional designs.
- American Coal Enterprises, Inc., Akron, Ohio wants DOE money to modify its "gas producing combustion" system that was developed for use on coal-burning locomotives in South Africa.
- Solar Turbines, Inc., San Diego would like to demonstrate the effectiveness of its impact separator in removing particulates from the gas stream leaving a slagging combustor.
- Foster Wheeler Development Corp., Livingston, New Jersey wants to develop a combination size-reduction/coal cleaning technology that will mix coal and water under high pressure, lower the pressure, and shatter the coal to a superfine size that will allow easy separation of ash.
- Management and Technical Consultants, Inc., Columbia, Md. wants to try out a burner technology called "pulse combustion."

DOE says contracts are being negotiated but it will spend $5.5 million on these projects in 1983. Contract lengths will vary from six months to four years.

Ontario Hydro to cut NO_x emission 50 percent

TORONTO, ONTARIO—Ontario Hydro says that it has started a 3-year program to reduce nitrogen oxide "acid gas" emission by 50 percent at its Nanticoke generating station near Hamilton, Ontario on Lake Erie. The Canadian utility says that this is one step toward its 1981 commitment to reduce total acid gas emissions by 50 percent by 1990.

The utility will retrofit low-NOx burners supplied by Babcock & Wilcox, Ltd. that will cut emissions by 25 percent from present levels. The rest of NOx reduction will be achieved by generating less electricity.

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Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

Supreme Court rules on two nuclear cases

Residents' fears should not be factor in TMI-1 restart decision

Don Minner
Assistant Editor

WASHINGTON, D.C.—Clearing the way for re-start of TMI-Unit 1, the U.S. Supreme Court unanimously ruled the Nuclear Regulatory Commission doesn't have to consider the psychological effect such an act would have on the residents of the area.

People Against Nuclear Energy (PANE), a Harrisburg group opposed to operation of either TMI reactor, contended that restarting the unit would "cause severe harm to the stability, cohesiveness and well being of the communities in the vicinity of the reactor." The group also said renewed operation of the unit would "cause severe psychological stress to PANE's members and other persons living in the vicinity of the reactor."

The Supreme Court reversed a ruling by the U.S. Court of Appeals for the District of Columbia that the NRC had failed to consider whether the risk of an accident at TMI-1 might cause harm to the psychological health and community well-being of the area residents.

The appeals court said the National Environmental Policy Act (NEPA) required the NRC to evaluate the "potential psychological health effects" of operating the reactor.

Court's opinion

Writing for the Supreme Court, Justice William Rehnquist said, "NEPA addresses environmental effects of federal actions. The gravity of harm does not change its character. If a harm does not have a sufficiently

Continued on page 2

States' right to ban new nuclear plants upheld by justices

WASHINGTON, D.C.—Delivering a potential damaging shot to the nuclear power industry, the Supreme Court has ruled that states may ban construction of new nuclear plants until the federal government creates a permanent radioactive waste disposal site.

Immediate impact of the ruling will be slight. The judgement applies only to plants not yet built, and no new plants are planned. Also, the Nuclear Waste Policy Act of 1982 orders the government to find a permanent waste depository by 1987.

Potential harm to the industry comes in the form of more states enacting legislation similar to the California statute that bars new nuclear plants. Other than California, eight states have laws or are taking legislative action to stop new plants from being built: Connecticut, Iowa, Maine, Massachusetts, Montana, Oregon, Wisconsin and New York.

The Reagan administration had argued that allowing states to ban any new plants discouraged the federal goal of developing nuclear energy.

Writing the majority opinion, Justice Byron White said, "...while the argument of Petitioners and the United States has considerable force, the legal reality remains that Congress has left sufficient authority in the states to allow the development of nuclear power to be slowed or even stopped for economic reasons."

In a friend-of-the-court brief, the federal government had said that such a decision would be "widely copied." "The result would be the virtual elimination of nuclear power as a po-

Continued on page 16

CG&E goes to court over Zimmer arbitration issues

CINCINNATI—Cincinnati Gas & Electric Company, principal owner and constructor of the beleaguered Zimmer nuclear plant, has gone to court to prevent other utility participants in the plant from pressing their claims for arbitration on construction issues.

CG&E sought, and the Court of Common Pleas for Hamilton County, Ohio granted a restraining order, prohibiting the furtherance of arbitration on issues that at the time of the ruling were being argued by CG&E, Dayton Power & Light, and Columbus & Southern Ohio Electric Company.

The court stayed DP&L and C&SOE from pressing their claims until such time as the court issued its final ruling on the merits of the case. However, the court allowed the parties to continue their work toward selecting an arbitrator if they so desired.

The Zimmer nuclear plant is currently under a Nuclear Regulatory Commission stop-work order covering all safety-related construction. CG&E has said it cannot estimate when construction of the plant will be completed, nor can it project final costs. The NRC issued the stop-work order last November because of serious quality assurance lapses in construction. The plant is about 97 percent complete.

With the date of operation and the final cost now uncertain, Dayton Power & Light decided earlier this year to exploit a clause in the tripartite ownership agreement that enabled the company to arbitrate con-

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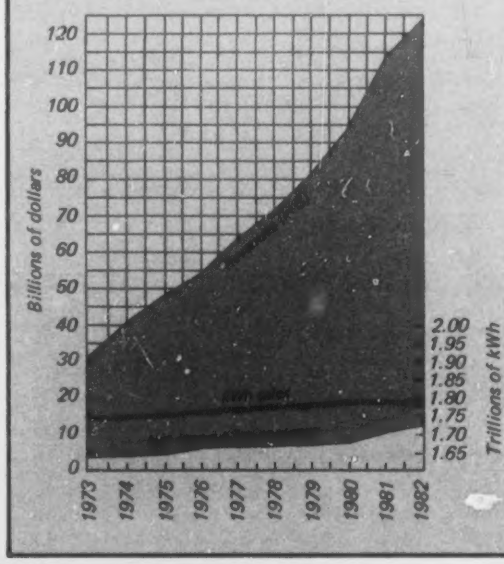
THE TOP 100 ELECTRIC UTILITIES
10 year record of performance



18TH ANNUAL TOP 100 ELECTRIC UTILITIES report, which begins on page 9, shows improved financial performance in 1982, despite a reduction in kilowatt-hour sales—the first sales decline in the 18-year history of this annual special report. Chart at left shows the 10-year trend for three important performance criteria, culminating in 1982 accomplishments for the industry's 100 largest companies. Revenues increased to $123.4 billion and net income rose to $12.3 billion, but kWh sales declined by 2.2 percent, to 1.8-trillion kWh, in the face of recessionary cutbacks in usage and milder than normal weather.

NRC fine proposed for Salem mishap is largest ever

WASHINGTON, D.C.—Citing the seriousness of the failure of the Salem-1 nuclear plant to automatically shut down on two occasions in February, 1983, the Nuclear Regulatory Commission staff has proposed fining Public Service Electric & Gas Co. $850,000 for alleged violations of agency requirements.

This is the largest fine ever proposed by the NRC.

At press time, a spokesman for PSE&G would not comment on the proposed NRC action, pending full review of agency allegations. The company had 30 days from May 6 to either pay the fine or protest it.

First ATWS goes unnoticed

According to the NRC, "After a decade of discussions on anticipated transients without scram (ATWS), the first licensed (pressurized water reactor) ATWS ever in the U.S. went totally unnoticed at unit 1 of the Salem nuclear power plant on February 22, 1983."

The terms "scram" and "trip" are used interchangeably to refer to a sudden shutting down of a reactor.

Electrical breakers (reactor trip breakers) designed to shut down the reactor failed to operate automatically, and the plant was subsequently shut down by control room operators.

A preliminary determination by the licensee and the reactor vendor concluded that the reactor trip circuit breakers had failed to operate because of excessive friction resulting from a lack of proper lubrication.

The NRC complaint charges that in permitting the failure of the electrical breakers, PSE&G violated the Salem unit 1 technical specifications that require two electrical breakers to be operable when the reactor is running.

The company also was alleged to have violated the requirements that the reactor be shut down within 6 hours if one of the automatic shutdown mechanisms fails; and for any automatic shutdown, for failing to determine the cause and take needed corrective action before the reactor is returned to service.

"Contrary to these requirements," the NRC said in its complaint, "PSE&G failed to recognize that the

Continued on page 18

Foreign Power Briefs

- **Nuclear plants in non-communist** countries produced 8.3 percent more power last year than in 1981, according to the Organization for Economic Cooperation and Development (OECD). OECD says nuclear power accounted for 14.8 percent of the electricity generated, compared to 13.5 percent a year ago. The agency expects the share to increase to 24 percent in 1990 and 29 percent by the year 2000.

- **Japan** will soon have the opportunity to use Atlantic Research Corporation's coal-water slurry. Sumitomo Corp. of Japan has signed with the firm to market its program, with an option to purchase a manufacturing and sale license. Atlantic had shipped four metric tons of its coal-water mixture to Japan last year. Sumitomo test fired it in its own boilers and is now ready to market the process throughout the country.

- **The Soviet Union** is expected to start talks this year toward allowing United Nations inspection of some of its civilian nuclear power plants, reports the Canadian Nuclear Association. Proposed inspections would be limited to plants with peaceful uses.

- **Rotterdam**, the Netherlands, will convert a 1000 MW natural-gas-fired electricity plant to coal at a cost of approximately $475 million. The move follows the city council's five-year plan to eliminate the use of high grade indigenous gas to fuel power plants. The conversion is expected to be completed by 1987. A spokesman said the 2.2 million tons of coal needed for the plant will be imported.

- **Hong Kong** got a big boost from Exxon Corporation, when the company announced it will spend $450 million to expand a coal-fired plant on the Kowloon Peninsula. An Exxon spokesman said the money, which is the firm's share of a $750 million joint venture, will help pay for two more 660 MW generators, in addition to the two 660 MW units already under construction. Exxon owns 60 percent of the project. China Power & Light Co., one of Hong Kong's two electric companies, owns 40 percent of the venture and will spend the remaining $300 million. The two units now under construction are expected to go on-line in 1986 and 1987.

- **Eight European and Far East** members of the Organization for Economic Cooperation and Development have joined the LOFT (Loss of Fluid Test) reactor safety program to conduct a worldwide investigation of the actualities of public risk from a major nuclear reactor accident. The OECD-LOFT Experimental Program will be managed by a scientific board with representatives from each participant. Austria, Finland, West Germany, Italy, Japan, Sweden, Switzerland and the United Kingdom have agreed to a joint three-year sponsorship of the safety test.

- **"Worldwide Remote Site Power Systems,"** a recent Frost & Sullivan study, reports that diesel generators will lose their dominance of the remote site power systems market as hybrid systems using natural energy grow dramatically over the next ten years. The study says that the increase in solar, wind and battery hybrid systems and the decline in diesels will be the major trend as output climbs to 9,554 MW in 1990, from 5,629 MW in 1982. Africa will be the best market for remote power systems, according to the report. It says capacity in that country should grow from 1,068 MW in 1982 to 2,936 MW in 1990.

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EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (••) All readers receive EL&P's industry news section.

Residents' fears . . . from page 1

close connection to the physical environment, NEPA does not apply.

"We do not understand how the accident at TMI-2 transforms PANE's contentions into environmental effects."

Section 102 of the Act says that where an agency action significantly affects the quality of the human environment, it must evaluate the "environmental impact of the proposed action" and any unavoidable adverse environmental effects of its proposal.

A spokesman for petitioner Metropolitan Edison Company said the utility is pleased with the decision, but still recognizes the concern in the community. "We reassert our pledge to the public that the plant will be operated safely," said John Fidler. "We also are renewing our pledge to provide complete, open communications so that the public will have the ability to judge for itself the safety of our operation."

William Gifford, vice president of communications for General Public Utilities Nuclear Corp., said, before the ruling was announced, that a favorable decision could mean a July restart for Unit-1.

Industry freed

American Nuclear Society President L. Manning Muntzing said the Court's decision freed the nuclear industry from having to consider the "fear" issue in licensing decisions.

Conrad MacKerron, spokesman for the nuclear watchdog group Critical Mass, said, "The ruling was unfortunate and disappointing. There's still a lot of anger and fear there. I don't know what GPU can do to allay those fears."

Justice Rehnquist wrote, "We do not mean to denigrate the fears of PANE's members, or to suggest that the psychological health damage they fear could not, in fact occur. Nevertheless it is difficult for us to see the differences between someone who dislikes a government decision so much that he suffers anxiety and stress, someone who fears the effects of that decision so much that he suffers similar anxiety and stress, and someone who suffers anxiety and stress that flow directly from the risks associated with the same decision."

The Court said NEPA wasn't intended to give citizens the chance to express policy objections to federal actions.

"It would be extraordinarily difficult for agencies to differentiate between 'genuine' claims of psychological health damage and claims that are grounded solely in disagreement with a democratically adopted policy," wrote Rehnquist.

In a concurring opinion Justice William Brennan wrote, "There can be no doubt that psychological injuries are cognizable under NEPA. As the Court points out, however, the particular psychological injury alleged in this case did not arise, for example, out of the direct sensory impact of a change in the physical environment, but out of a perception of risk."

The Court held that NEPA does not require agencies to evaluate "the effects of risk, qua risk."

Restart soon?

To GPU, the ruling means that a restart of Unit 1 could be imminent. Fidler said the plant will be "mechanically ready" for restart by July.

The NRC's Atomic Safety and Licensing Board for TMI-1 has recommended that the unit be allowed to restart. However, a spokesman for the NRC said that no final date has been made for a NRC ruling on the recommendation.

GPU President Herman Dieckar , told the House Committee on Interior and Insular Affairs that technical modifications to the unit are nearly complete. Out of 130 modifications, he said that 108 are in place and about 100 have received NRC certification.

Dieckamp said unit 1 steam generator repairs have been completed and they "have been restored to a condition that is structurally and thermodynamically indistinguishable, by analysis and non-destructive tests, from the initial design requirements which underlie the licensing of the plant."

Zimmer arbitration . . . from page 1

struction issues that became contentious among the parties.

DP&L is seeking an expanded role in utility efforts to complete construction of the plant. In addition, DP&L has called for the establishment of an owners' group to assume overall management authority for the remaining construction. And the utility has not only raised the issue of damages that might accrue to it as a result of the cost and scheduling overruns, but also has questioned whether the basic ownership agreement needs to be modified.

In its complaint, CG&E said it was not obligated to arbitrate whether DP&L must continue to pay all costs of completion of the Zimmer nuclear station, nor "whether CG&E had sufficient knowledge that actions against suppliers for failure to comply with contractual obligations should have been initiated or other available remedies pursued."

CG&E further contends that it is not required to arbitrate percentage ownerships as stipulated in the Zimmer basic generating agreement, nor is it required to enter into negotiations over whether the provisions of the generating agreement need to be modified.

Cincinnati Gas & Electric says that many of the issues that DP&L seeks to debate are not subject to arbitration as defined by the scope of the arbitration clause in the basic generating agreement. CG&E further argues that the relief sought is outside the arbitrator's power to grant, and that even if relief could be granted, it would be in direct conflict with the terms of the generating agreement. Other contentions were raised as well.

According to DP&L spokesman Stephen Koziar, DP&L promptly filed a counterclaim, arguing that the basic ownership agreement clearly states that all issues falling into contention are subject to arbitration, and that if even some issues are considered not arbitrable, this is for the commonly-chosen arbitrator to decide, not the state court.

Construction drop forecast

WASHINGTON, D.C.—Utility construction expenditures will drop in 1986, says Dr. John R. Parker, an Ebasco Services consultant.

Utilities spent $40.2 billion on construction in 1982. Parker says expenditures will fall to $33.3 billion in 1986 before rising again.

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18th Annual Top 100 Electric Utilities Report

Revenue and earnings performance masked continuing investor-owned utility problems

Robert A. Lincicome
EL&P Editor-in-Chief

At first glance, the Top 100 Electric Utilities Report seems to indicate that the nations 100 largest investor-owned electric utilities performed well in 1982.

After a strong recovery year in 1981, the Top 100 realized a nominally healthy revenue gain in 1982, and an even stronger increase in Net Income. Earnings, despite substantial increases in shares outstanding, were up a solid, although unspectacular 6.4 percent. In fact the only drab performance reported by the nation's biggest utility companies was the downturn in kilowatthour sales.

But the obvious successes of the year weren't really all that they first appeared. The fact remains that the by-product of large-scale construction programs—the enormous amounts of Allowance for Funds Used During Construction shown on utility income statements—has distorted the industry's true financial strength.

As 'Man does not live by bread alone,' neither does a utility company live by the bottom line alone. When one goes beyond the mere numbers on the bottom line of utility profit and loss statements, it is clear that the strength of net incomes of the majority of the Top 100 Electric Utilities is illusionary, that AFUDC has created a substantial overstatement of the real dollar strength of most investor-owned electric utility earnings. For many utilities, the inclusion of AFUDC creates a picture of earnings strength when, in fact, it really has created a severe cash flow problem.

To see the serious nature of the problem, which most state Public Utility Commissions have refused to deal with, it is necessary only to check a random sample of utility P&L statements to determine what portion of net income is represented by AFUDC. For those companies that have been fortunate enough to complete large construction projects, such as Potomac Electric Power or Kentucky Utilities, AFUDC can be low, perhaps in the 10- to 20-percent range. But for companies still involved in large-scale generation projects, and especially those involved in nuclear plant construction—companies such as Middle South Utilities, Detroit Edison, PS of New Hampshire or Kansas Gas & Electric—AFUDC can run as high as 100 percent of net income *or more*.

On average, according to recent Congressional subcommittee testimony by John Barr, a principal of Morgan Stanley Inc., AFUDC represents more than 50 percent of all electric utility industry earnings, all non-cash. At the same time, the average utility cash dividend payout runs about 75 percent of earnings. Obviously, when cash earnings are one-third less than cash dividends, there is a problem and for investors, a substantial one. And when investors have a problem accepting utility earnings, the utilities have problems too.

It must be noted, however, that the problem is a short-term one. As utilities are able to complete their huge construction programs, bringing units on line and getting construction budgets under control again, the problem of AFUDC diminishes.

But until then, AFUDC remains a serious concern and a factor that mitigates against apparent success.

Summary achievements

During 1982, the Top 100 Electric Utilities generated revenues of $123.4-billion. This represents an increase of 9.5 percent from 1981 revenues. It reflects the effect of rate increases granted by state public utility commissions since kilowatthour sales were depressed because of the recession and cutbacks in use. Also included in revenues were collections under fuel adjustment clauses and the net proceeds of subsidiary activities.

The higher revenues came on sale of 2.2 percent fewer kilowatthours. A 6-percent reduction in industrial electric usage brought on by the recession was the prime culprit. Milder than normal weather during the last three calendar quarters also contributed to the sales downturn.

Net Incomes of the Top 100 Electric Utilities increased substantially faster, which reflects the strong efforts of top utility managements to reduce expenses and improve the productivity of their companies. Net Income climbed 20.6 percent, to $12.3-billion. In 1981, Net Income was $10.2-billion and a year earlier was $8.35-billion.

The gain, 20.6 percent, was the second largest annual increase in the past decade. The gain in 1981 was a record 22.2 percent.

The growth of Net Income was mitigated again in 1982 by sales of large blocks of common stock. Nevertheless, individual per-share earnings increased substantially, by 6.4 percent, to $3.00 per average share. 1982 was the second year of solid increases. In 1981 per-share earnings were $2.82. Earlier per-share earnings were: 1980—$2.52; 1979—$2.51; 1978—$2.50 and 1977—$2.42.

Kilowatthour sales by The Top 100 Electric Utilities fell 2.2 percent in

EARNINGS GROWTH STATISTICS

Company Name	Rank	% Change From 1981	1982 Earnings Per Share
Tucson Electric Power	1	113.95	$8.13
Otter Tail Power	2	69.77	$2.92
General Public Utilities	3	66.67	$0.55
Empire District Electric	4	58.65	$2.11
Idaho Power	5	54.43	$4.71
Sierra Pacific Power	6	52.03	$2.28
Texas-New Mexico Power	7	51.05	$3.61
Pacific Gas & Electric	8	43.99	$4.91
Montana-Dakota Utilities	9	40.83	$4.07
Northeast Utilities	10	36.43	$1.76
Public Service of Indiana	11	33.04	$4.55
Southern Company	12	31.49	$2.38
Kentucky Utilities	13	28.11	$2.78
United Illuminating	14	27.12	$5.39
Southwestern Public Service	15	26.11	$2.27
Iowa Public Service	16	25.52	$3.00
Oklahoma Gas & Electric	17	25.37	$2.57
San Diego Gas & Electric	18	23.93	$2.90
Madison Gas & Electric	19	23.49	$2.05
Public Service Electric & Gas	20	23.19	$3.24
Northern States Power	21	23.14	$4.79
Wisconsin Electric Power	22	22.87	$3.60
Commonwealth Edison	23	22.55	$3.75
Indianapolis Power & Light	24	21.35	$3.41
Delmarva Power & Light	25	19.66	$2.13
Cincinnati Gas & Electric	26	19.57	$2.75
Cleveland Electric Illuminating	27	19.44	$3.01
Interstate Power	28	18.84	$2.46
Nevada Power	29	18.50	$4.10
Central Illinois Light	30	16.67	$2.80
Minnesota Power	31	15.08	$3.51
Wisconsin Power & Light	32	15.08	$3.51
New England Electric System	33	14.81	$4.65
Iowa-Illinois Gas & Electric	34	14.49	$3.95
Union Electric	35	14.21	$2.17
New York State Electric & Gas	36	13.90	$3.36
Northern Indiana Public Service	37	13.14	$1.55
Allegheny Power System	38	12.54	$3.41
Duke Power	39	12.54	$3.59
Niagara Mohawk Power	40	12.34	$2.64
Florida Power & Light	41	12.24	$4.77
Virginia Electric & Power	42	11.86	$1.98
Central Maine Power	43	11.60	$2.02
Iowa Electric Light & Power	44	11.17	$2.19
Central & South West	45	11.02	$2.82
Eastern Utilities Associates	46	10.84	$2.25
Commonwealth Energy Systems	47	10.36	$2.45
Consolidated Edison	48	10.25	$3.55
Orange & Rockland	49	10.21	$2.59
Public Service of Colorado	50	10.15	$2.17
Baltimore Gas & Electric	51	10.00	$4.07
Texas Utilities	52	9.69	$3.85
Kansas Power & Light	53	9.09	$3.60
Pacific Power & Light	54	7.45	$3.03
Illinois Power	55	7.04	$3.04
Potomac Electric Power	56	6.54	$2.28
Philadelphia Electric	57	6.22	$2.39
South Carolina Electric & Gas	58	5.94	$2.32
Long Island Lighting	59	5.88	$2.70
Pennsylvania Power & Light	60	5.68	$3.35
Dayton Power & Light	61	5.58	$2.65
Kansas Gas & Electric	62	5.26	$3.00
Central Hudson Gas & Electric	63	5.11	$3.91
Wisconsin Public Service	64	4.67	$3.14
Central Illinois Public Service	65	4.62	$1.81
Hawaiian Electric	66	4.59	$4.10
Southern California Edison	67	4.06	$5.13
Utah Power & Light	68	3.93	$2.38
Carolina Power & Light	69	3.69	$3.17
Iowa Resources	70	3.39	$3.66
El Paso Electric	71	3.14	$2.30
Public Service of New Hampshire	72	3.02	$2.73
Southern Indiana Gas & Electric	73	3.01	$3.42
Central Vermont Public Service	74	1.34	$3.79
Consumers Power	75	1.28	$3.16
Arizona Public Service	76	1.23	$3.30
Central Louisiana Electric	77	0.41	$2.47
Rochester Gas & Electric	78	−1.06	$2.81
Montana Power	79	−1.73	$3.97
Toledo Edison	80	−2.75	$3.18
Washington Water Power	81	−3.65	$3.17
Middle South Utilities	82	−4.51	$2.33
Duquesne Light	83	−4.85	$1.96
Portland General Electric	84	−6.30	$2.38
Ohio Edison	85	−7.39	$2.13
Tampa Electric	86	−8.33	$2.75
Gulf State Utilities	87	−12.95	$1.95
Detroit Edison	88	−13.37	$1.75
Kansas City Power & Light	89	−13.46	$4.18
American Electric Power	90	−14.35	$2.03
Missouri Public Service	91	−14.63	$2.10
Louisville Gas & Electric	92	−18.45	$2.21
Puget Sound Power & Light	93	−19.93	$2.29
Florida Power Corporation	94	−21.43	$2.20
Boston Edison	95	−23.37	$3.18
Public Service of New Mexico	96	−23.88	$3.22
Atlantic Electric	97	−39.27	$1.84
Savannah Electric & Power	98	−41.42	$1.40
Houston Lighting & Power	99	−48.41	$1.62
Centel (Electric properties only)	100	N/A	N/A

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SALES DATA

		1982 Total Sales (KWH)		1982 Sales (KWH) By Type of Customer (% of Sales)				Average Annual Residential Use		Ratio of Long Term Debt to Net Plant	
Company	Rank	% Increase	Average Annual Growth 1976 – 1981	Resid.	Comm.	Ind'l.	Other	1982	1981	1982	1981
Niagara Mohawk Power	1	29.13	−3.88	26.0	28.6	31.8	13.7	6,878	6,914	46.7	45.2
Otter Tail Power	2	26.79	4.43	25.7	13.4	28.6	32.3	10,008	9,190	38.9	39.9
Idaho Power	3	19.54	5.74	22.9	22.4	23.5	31.2	14,939	14,054	43.6	47.0
Utah Power & Light	4	14.45	6.40	19.8	14.8	34.1	31.3	8,250	7,821	47.3	46.8
Public Service of New Mexico	5	12.69	6.38	17.5	23.3	12.1	47.1	5,751	5,698	43.9	44.7
Central Vermont Public Service	6	10.43	5.14	34.3	8.1	30.0	27.6	7,880	7,866	50.0	59.9
Montana-Dakota Utilities	7	8.15	5.54	42.9	24.6	28.7	3.8	7,972	7,463	36.7	45.3
Empire District Electric	8	5.09	1.18	31.4	20.0	27.6	21.0	8,879	8,543	46.5	46.9
Puget Sound Power & Light	9	4.99	7.24	47.5	23.1	14.8	14.5	15,143	14,626	47.6	48.8
Central Maine Power	10	4.95	2.78	36.8	22.8	37.4	3.0	6,875	6,777	46.1	51.1
Philadelphia Electric	11	4.57	0.79	26.6	10.6	48.0	14.8	6,544	6,699	46.9	48.1
Southwestern Public Service	12	4.00	2.86	14.6	16.3	42.2	27.0	7,328	7,148	44.6	46.1
Northern States Power	13	3.85	−0.44	28.0	14.0	39.9	18.1	7,337	7,135	37.5	38.0
Texas Utilities	14	3.44	3.50	33.0	27.3	29.0	10.7	12,320	11,862	40.8	40.9
Iowa Electric Light & Power	15	3.30	1.78	34.3	25.2	31.5	9.0	8,097	7,894	42.6	44.6
Southern Company	16	2.73	2.08	24.9	19.0	34.5	21.6	10,396	10,645	53.0	55.1
Pacific Power & Light	17	2.68	4.46	28.8	20.7	26.6	23.9	12,621	12,609	49.0	54.3
Central Illinois Public Service	18	2.52	0.14	25.6	10.6	38.9	24.8	8,328	8,090	37.5	41.0
Potomac Electric Power	19	2.07	2.39	23.9	41.9	25.0	9.2	8,643	8,790	48.1	44.6
Florida Power & Light	20	1.75	4.65	48.2	35.6	7.3	8.9	10,757	11,216	41.7	41.9
Sierra Pacific Power	21	1.49	1.24	30.9	36.8	22.7	9.6	7,524	7,285	42.0	43.0
San Diego Gas & Electric	22	1.22	3.30	35.6	33.0	23.9	7.5	5,388	5,471	38.2	40.5
Indianapolis Power & Light	23	1.17	0.80	31.7	21.7	45.5	1.1	9,417	9,328	37.0	42.4
Iowa Resources	24	1.10	0.77	39.9	25.2	32.3	2.6	8,279	7,988	43.4	39.9
Texas-New Mexico Power	25	0.93	5.29	28.6	20.4	46.7	4.3	10,322	10,244	42.5	40.3
Missouri Public Service	26	0.66	1.50	38.9	25.5	18.5	17.1	7,973	7,857	45.9	51.9
Interstate Power	27	0.64	4.18	21.4	16.0	46.7	15.9	7,055	6,790	49.3	52.1
Orange & Rockland	28	0.41	−1.79	31.4	21.2	28.9	18.5	5,827	5,926	43.1	41.3
Wisconsin Public Service	29	0.22	3.30	26.8	23.1	30.3	19.8	7,025	7,172	34.6	41.5
Virginia Electric & Power	30	0.19	2.51	33.2	24.7	17.5	24.6	10,641	10,948	53.3	52.6
Boston Edison	31	0.05	2.15	22.0	41.0	15.5	21.5	5,224	5,190	50.2	5.2
Kansas Power & Light	32	−0.01	1.86	28.1	33.5	23.5	14.8	7,644	7,545	39.8	38.2
Carolina Power & Light	33	−0.01	2.37	25.1	17.5	31.2	26.2	11,663	12,087	45.1	45.4
Public Service of New Hampshire	34	−0.11	1.75	29.4	11.1	29.0	30.5	6,946	6,949	45.0	39.1
Public Service of Colorado	35	−0.26	4.03	28.8	44.9	18.9	7.5	5,963	5,734	41.2	41.6
Commonwealth Energy Systems	36	−0.55	−2.06	23.5	21.7	9.1	45.8	5,558	5,491	39.2	43.6
Houston Lighting & Power	37	−0.62	4.79	24.5	18.3	51.1	6.1	13,501	13,590	41.2	40.2
Union Electric	38	−0.75	1.04	32.8	30.5	29.6	7.1	9,108	8,955	48.5	47.3
Nevada Power	39	−1.04	5.99	43.1	2.2	47.8	6.9	13,720	14,527	49.4	48.9
Madison Gas & Electric	40	−1.08	2.72	27.3	46.0	5.4	21.2	6,101	6,073	38.0	39.1
New England Electric System	41	−1.18	0.93	35.9	30.0	24.1	10.0	6,039	6,023	40.1	43.8
El Paso Electric	42	−1.29	2.81	27.2	29.5	17.4	25.9	5,869	5,849	40.3	31.3
Atlantic Electric	43	−1.47	2.80	43.2	33.9	21.8	1.1	7,444	7,751	44.9	47.0
United Illuminating	44	−1.60	−0.20	35.6	35.3	27.6	1.6	6,213	6,312	44.1	41.9
Illinois Power	45	−1.65	1.95	27.0	17.7	44.5	10.8	8,051	8,011	41.2	39.1
Baltimore Gas & Electric	46	−1.66	2.75	35.3	17.4	47.3	0.0	7,872	7,848	45.9	50.0
Hawaiian Electric	47	−1.73	1.98	28.1	21.7	49.3	0.9	6,815	7,173	39.3	40.7
Consolidated Edison	48	−1.79	0.20	25.8	59.4	5.1	9.7	3,199	3,231	39.3	42.5
Montana Power	49	−1.83	6.13	22.3	19.7	28.0	30.0	8,712	7,977	56.0	50.3
Oklahoma Gas & Electric	50	−1.97	5.32	27.2	17.7	22.7	32.4	10,922	10,515	42.8	43.6
Delmarva Power & Light	51	−1.97	1.42	28.0	23.9	31.1	17.1	7,860	7,967	44.0	48.9
Pacific Gas & Electric	52	−1.98	1.24	31.6	30.9	26.2	11.3	6,252	6,489	45.8	44.4
General Public Utilities	53	−2.06	1.51	33.8	26.1	34.3	5.8	7,419	7,560	51.2	53.3
Wisconsin Power & Light	54	−2.13	2.83	30.9	16.8	27.7	24.6	7,988	7,805	42.3	45.2
Cincinnati Gas & Electric	55	−2.13	2.03	35.5	23.9	30.6	10.1	9,570	9,592	48.5	48.2
South Carolina Electric & Gas	56	−2.32	1.09	31.5	24.8	33.9	9.7	11,712	12,183	43.3	44.2
Long Island Lighting	57	−2.35	1.05	42.5	2.0	47.9	7.6	6,729	6,815	96.8	99.7
Dayton Power & Light	58	−2.44	0.68	35.9	20.3	28.5	15.3	9,556	9,591	51.4	48.7
New York State Electric & Gas	59	−2.57	1.52	41.1	23.2	24.4	11.3	7,306	7,393	45.3	42.8
Ohio Edison	60	−2.58	2.19	28.0	20.8	32.1	19.1	7,723	7,760	44.3	45.5
Portland General Electric	61	−2.62	5.65	38.0	26.3	21.7	14.0	12,691	12,181	49.7	54.1
Kentucky Utilities	62	−2.71	−0.12	31.0	19.2	17.3	32.5	10,304	10,334	43.3	48.2
Public Service Electric & Gas	63	−2.72	1.07	26.4	38.1	33.9	1.6	5,156	5,261	42.7	44.3
Pennsylvania Power & Light	64	−2.86	1.65	36.1	26.7	32.8	4.4	9,039	9,157	46.1	47.7
Wisconsin Electric Power	65	−2.88	0.98	30.9	24.7	33.5	10.9	7,209	7,149	41.7	45.5
Central & South West	66	−2.95	4.11	26.2	20.8	30.4	22.6	10,181	9,894	38.3	41.0
Kansas City Power & Light	67	−2.96	1.06	29.5	41.4	24.3	4.9	7,754	7,700	81.1	72.3
Middle South Utilities	68	−2.97	1.85	30.4	18.7	43.0	8.0	11,306	11,347	49.7	50.8
Kansas Gas & Electric	69	−3.08	0.70	27.6	20.7	35.9	15.8	9,529	9,433	43.1	49.7
Iowa Public Service	70	−3.16	2.86	35.3	24.6	29.1	10.9	7,020	6,919	49.9	50.7
Toledo Edison	71	−3.26	−0.90	27.6	19.2	41.5	11.7	7,906	7,966	46.2	45.6
Arizona Public Service	72	−3.27	5.54	29.0	30.7	18.8	21.5	9,840	10,247	43.4	45.7
Commonwealth Edison	73	−3.27	−0.07	29.0	31.8	28.0	11.2	6,310	6,291	47.3	47.7
Florida Power Corporation	74	−3.58	4.42	39.6	20.8	14.5	25.2	9,964	10,758	48.5	46.6
Louisville Gas & Electric	75	−3.58	−1.45	32.0	25.4	31.7	10.8	8,926	8,981	41.0	40.5
Duke Power	76	−4.05	1.92	26.7	19.6	37.7	16.0	12,065	12,392	42.5	42.4
Consumers Power	77	−4.17	0.00	32.1	25.1	39.0	3.8	6,321	6,386	78.2	65.5
Savannah Electric & Power	78	−4.35	1.14	37.1	28.1	31.2	3.6	10,019	10,340	58.2	54.2
Northeast Utilities	79	−4.70	0.82	37.5	31.5	24.9	6.2	7,361	7,548	54.5	48.3
Rochester Gas & Electric	80	−4.74	0.92	27.6	22.9	25.6	23.9	6,745	6,671	46.1	46.6
Southern California Edison	81	−5.00	1.64	27.6	30.1	30.7	11.6	5,685	5,879	47.3	47.5
Gulf State Utilities	82	−5.11	3.63	22.7	16.5	52.0	8.8	13,015	12,786	81.9	105.1
Eastern Utilities Associates	83	−5.13	2.15	28.1	25.8	19.1	27.1	5,474	5,449	48.4	54.2
Iowa-Illinois Gas & Electric	84	−5.15	2.11	24.3	28.6	41.6	5.5	6,027	5,998	38.9	39.9
Allegheny Power System	85	−5.25	9.05	20.9	11.6	32.5	35.0	8,726	8,788	45.6	46.0
Detroit Edison	86	−5.96	−1.42	31.1	19.5	43.0	6.4	6,133	6,243	47.2	47.1
Public Service of Indiana	87	−6.15	1.92	27.9	20.7	32.0	19.4	10,411	10,329	38.5	39.8
Centel (Electric properties only)	88	−6.36	1.66	27.6	26.8	21.3	24.4	6,465	6,461	0.0	0.0
Washington Water Power	89	−6.46	8.86	34.4	18.6	15.1	32.0	15,221	14,697	47.3	53.2
Tampa Electric	90	−7.31	2.56	35.2	24.1	34.0	6.8	11,646	12,708	36.6	39.9
Cleveland Electric Illuminating	91	−7.67	−0.62	26.8	25.9	43.8	3.4	6,490	6,548	43.3	44.4
Northern Indiana Public Service	92	−7.95	−0.29	18.0	3.9	68.8	9.3	6,716	6,720	47.0	49.6
Central Hudson Gas & Electric	93	−8.95	5.74	23.0	20.5	23.3	33.2	6,142	6,268	78.5	69.8
Central Illinois Light	94	−11.42	1.33	33.0	23.1	41.5	2.3	8,384	8,434	38.0	37.5
American Electric Power	95	−13.69	4.92	22.6	14.4	30.3	32.6	9,898	10,032	54.5	54.8
Southern Indiana Gas & Electric	96	−15.37	3.28	25.9	20.0	37.7	16.4	10,173	10,081	43.0	48.5
Tucson Electric Power	97	−16.08	4.13	22.6	18.5	27.9	30.9	7,672	7,694	54.0	51.4
Minnesota Power	98	−18.16	10.49	11.0	9.2	55.4	24.3	7,928	7,878	47.7	45.0
Duquesne Light	99	−19.02	0.91	25.8	37.7	35.3	1.1	5,068	5,698	47.5	49.3
Central Louisiana Electric	100	−24.68	6.40	35.9	22.2	29.4	12.5	11,354	11,288	29.1	49.9

1982, to 1.80-trillion kWh. In 1981, sales totalled 1.84-trillion kWh. The sales decline is the first in the 18 year history of the Top 100 survey and reflects the effect of reduced industrial production and generally slower economic activity during the continuing recession. In addition, milder-than-normal weather persisted after the super-frigid days of the first quarter.

The 2.2 percent drop in kWh sales experienced by the Top 100 companies is about 0.7-percent greater than the decline in sales for the entire electric utility industry. This reflects the proportionately larger industrial load served by the Top 100 companies, compared with the less-industrialized territories of smaller investor-owned utilities, co-ops and municipal electric departments.

TABLE I
THE TOP 10 IN KWH SALES

Rank				
'82	'81	Company	KWH Sales (millions)	'82 % Change
1	1	American Electric Power		−13.69
2	2	Southern Company	96,787	2.73
3	4	Pacific Gas & Electric	60,446	−1.98
4	6	Texas Utilities	60,380	3.44
5	3	Southern California Edison	59,327	−5.00
6	5	Commonwealth Edison	59,225	−3.27
7	7	Houston Lighting & Power	56,529	−0.62
8	9	Middle South Utilities	51,400	−2.97
9	8	Duke Power	51,380	−4.05
10	11	Florida Power & Light	47,073	1.75

Interestingly, only seven utilities posted kWh sales gains greater than the average 7-percent rate experienced by the entire industry from 1945 through 1973. Overall, 31 utilities reported positive gains in kWh sales, while 69 suffered declines. The median sales growth performance was a -1.97 percent.

The 10 companies recording the largest total kWh sales are shown in Table I.

Average residential use inched upward again in 1982 to 8479 kWh, after falling substantially in 1981. But the 1982 gain, a mere 9 kWh, did not begin to makeup for the 303 kWh loss of the previous year.

As in previous years, the companies posting the highest average residential uses were located in the Pacific Northwest, where rates historically have been the lowest in the country, and in the hot-box states like Texas, Nevada and North Carolina. Companies posting the highest average residential kWh uses in 1982 were: 1. Washington Water Power, 15,221 kWh (+3.6 percent); 2. Puget Sound Power & Light, 15,143 kWh (+3.5 percent); 3. Idaho Power, 14,939 kWh (+6.3 percent); 4. Nevada Power, 13,720 kWh (-5.6 percent); and 5. Houston Lighting & Power, 13,501 kWh (-0.7 percent).

Companies reporting the lowest average residential use were: 100. Consolidated Edison, 3,199 kWh (-1.0 percent); 99. Public Service Electric & Gas, 5,156 kWh (-2.0 percent); 98. Boston Edison, 5,224 kWh (+0.7 percent); 97. San Diego Gas & Electric, 5,388 kWh (-1.5 percent) and 96. Eastern Utilities Associates, 5,474 kWh (+0.5 percent).

Revenues up again

Total revenues reported by the Top 100 Electric Utilities for 1982 were $123.4-billion. This compares with $112.7-billion in 1981 and represents a 9.5 percent increase, the smallest gain in more than a decade. With kWh sales off, the gain in revenues represents the effect of rate increases.

There were few large gainers in 1982. Only 9 companies recorded 1982 increases in excess of last year's average increase, 20.8 percent.

The largest revenue gains were posted by Montana Dakota Utilities, up 46.4 percent on an 8.1 percent increase in kWh sales; Otter Tail Power, ahead 33.4 percent on a healthy 26.8 percent increase in kWh sales and Public Service of New Mexico, which posted revenue gains of 26.9 percent on a 12.7 percent increase in sales.

TABLE II
LARGEST ELECTRIC UTILITY REVENUE PRODUCERS

(more than $2-million in revenues)

Rank '82	Rank '81	Company	Revenues (millions)	'82 % Change
1	1	Pacific Gas & Electric	$6,785.1	9.5
2	2	Consolidated Edison	$5,067.4	4.1
3	3	Southern Company	$4,927.2	15.8
4	5	Southern California Edison	$4,303.6	6.1
5	4	American Electric Power	$4,180.0	-0.3
6	6	Common-wealth Edison	$4,130.0	10.5
7	7	Public Service Electric & Gas	$3,874.0	11.6
8	10	Houston Lighting & Power	$3,478.8	25.6
9	11	Texas Utilities	$3,238.0	18.2
10	8	Florida Power & Light	$2,940.8	-4.8
11	9	Middle South Utilities	$2,901.7	4.7
12	12	Consumers Power	$2,731.1	0.0
13	15	Niagara Mohawk Power	$2,393.8	11.3
14	17	Central & South West	$2,389.3	14.0
15	13	Philadelphia Electric	$2,644.8	8.7
16	16	General Public Utilities	$2,405.5	16.5
17	14	Virginia Electric & Power	$2,360.8	9.2
18	19	Duke Power	$2,244.5	17.6
19	18	Detroit Edison	$2,123.3	3.4

In addition, 23 companies reported revenues between $1-billion and $2-billion.

At the other end of the scale were Tampa Electric, ranked 100 with a revenue decrease of 7.1 percent on kWh sales that were down 7.3 percent; Duquesne Light (99th), down 6.3 percent on a kWh-sales reduction of 19 percent; and Atlantic Electric (98th), down 5.4 percent on a slight 1.5 percent dropoff in kWh sales.

The number of companies that posted revenues in excess of $1-billion (See Table II) increased by two in 1982, to 42 companies. The first three companies, ranked by revenue size—1. Pacific Gas & Electric, 2. Consolidated Edison and 3. The Southern Company—were the same as in 1981. There were numerous minor shifts in rankings among the remaining large producers. The two newcomers to the Billion Dollar Club were Boston Edison ($1.056-billion) and Arizona Public Service ($1.064-billion).

Net incomes climbed

Total net income produced by the Top 100 Electric Utilities rose a substantial 20.6 percent in 1982, to $12.3 billion. Significantly, this is the second highest increase in net income in the past decade, close behind the 22.2 percent gain last year. The increase is even more outstanding in the light of

FINANCIAL STATISTICS

Company	Net Income		Revenue		Sales (KWH)		Int. Cov. Ratio		Earnings Per Share	Price/Share 1982 (Dollars)		% Change Long Term Debt
	Rank	% Gain	Rank	% Gain	Rank	% Gain	1982	1981	1982	High	Low	1982
Tucson Electric Power	1	119.0	9	21.6	97	-16.1	4.99	2.20	$8.13	24.875	17.750	24.63
Otter Tail Power	2	82.6	2	33.4	2	26.8	2.27	1.00	$2.92	22.500	16.125	-1.60
Texas-New Mexico Power	3	72.3	5	24.1	25	0.9	1.74	1.09	$3.61	22.750	16.000	19.74
Empire District Electric	4	65.2	31	14.7	8	5.1	2.61	1.49	$2.11	14.375	9.875	0.00
General Public Utilities	5	64.2	25	16.5	53	-2.1	0.60	0.21	$0.55	7.500	4.500	-2.76
Idaho Power	6	59.5	7	22.7	3	19.5	2.47	1.13	$4.71	29.125	20.500	-3.73
Public Service of Indiana	7	59.1	43	12.4	87	-6.1	6.13	3.20	$4.55	27.500	20.125	13.23
Northeast Utilities	8	59.0	73	6.5	79	-4.7	1.74	1.06	$1.76	12.500	8.875	17.80
Pacific Gas & Electric	9	52.6	57	9.5	52	-2.0	2.40	1.37	$4.91	28.750	20.250	12.65
Kentucky Utilities	10	47.9	65	8.8	62	-2.7	2.04	1.31	$2.78	21.750	15.625	-4.71
Southern Company	11	44.9	27	15.8	16	2.7	1.66	1.34	$2.38	15.875	11.000	4.99
Montana-Dakota Utilities	12	44.6	1	46.4	7	8.1	4.81	3.02	$4.07	25.000	17.875	-14.17
Commonwealth Edison	13	43.9	53	10.5	73	-3.3	1.26	1.04	$3.75	25.875	19.250	9.60
San Diego Gas & Electric	14	43.5	6	23.4	22	1.2	2.35	1.24	$2.90	17.875	11.750	7.95
Cleveland Electric Illuminating	15	41.3	59	9.4	91	-7.7	2.03	1.84	$3.01	20.000	14.750	8.47
Southwestern Public Service	16	40.7	22	16.6	12	4.0	2.82	2.57	$2.27	17.000	11.625	9.08
Florida Power & Light	17	39.8	95	-4.8	20	1.8	1.57	1.52	$4.77	37.625	28.125	12.34
United Illuminating	18	38.9	91	-3.2	44	-1.6	2.65	2.27	$5.39	26.375	18.625	22.76
Oklahoma Gas & Electric	19	38.8	56	9.9	50	-2.0	3.29	2.50	$2.57	19.500	13.375	8.08
Eastern Utilities Associates	20	36.2	92	-3.2	83	-5.1	1.20	0.91	$2.25	14.625	11.000	6.04
Public Service Electric & Gas	21	35.9	47	11.6	63	-2.7	2.37	1.92	$3.24	23.750	17.750	7.01
Cincinnati Gas & Electric	22	35.8	24	16.6	55	-2.1	1.67	1.46	$2.75	20.000	14.625	8.84
New York State Electric & Gas	23	35.7	26	15.9	59	-2.6	1.96	2.09	$3.36	21.750	14.000	34.15
Northern Indiana Public Service	24	33.8	48	11.3	92	-7.9	1.35	1.55	$1.55	13.875	10.250	13.02
Kansas Gas & Electric	25	32.9	45	12.1	69	-3.1	3.93	2.93	$3.00	18.500	14.625	1.07
Nevada Power	26	32.6	20	17.1	39	-1.0	2.18	2.56	$4.10	27.875	20.125	19.95
Delmarva Power & Light	27	32.4	76	4.6	51	-2.0	2.70	1.86	$2.13	16.500	11.500	-5.65
Indianapolis Power & Light	28	31.8	15	18.1	23	1.2	2.52	1.93	$3.41	27.875	20.625	-7.85
Iowa Public Service	29	29.8	28	15.1	70	-3.2	1.84	1.59	$3.00	23.875	16.500	0.23
Union Electric	30	29.7	54	10.1	38	-0.7	1.28	1.30	$2.17	14.750	10.750	16.31
South Carolina Electric & Gas	31	29.4	29	15.1	56	-2.3	2.51	1.98	$2.32	19.125	14.500	10.33
Wisconsin Electric Power	32	28.9	39	13.1	65	-2.9	3.49	2.68	$3.60	25.750	17.500	-6.82
El Paso Electric	33	28.7	68	7.9	42	-1.3	4.94	4.90	$2.30	12.625	9.000	60.90
Central Maine Power	34	28.1	51	10.9	10	4.9	1.85	1.39	$2.02	17.125	12.000	-0.21
Illinois Power	35	27.0	30	14.8	45	-1.7	2.30	2.22	$3.04	23.875	18.625	20.10
Madison Gas & Electric	36	27.0	21	16.7	40	-1.1	3.15	2.65	$2.05	19.000	13.750	-0.36
Northern States Power	37	26.3	8	21.9	13	3.9	3.42	3.06	$4.79	32.500	23.375	4.94
Sierra Pacific Power	38	25.6	11	20.7	21	1.5	1.52	1.26	$2.25	13.875	10.250	6.45
Long Island Lighting	39	25.4	90	-1.9	57	-2.4	2.18	2.16	$2.70	18.000	13.625	16.78
Dayton Power & Light	40	24.6	37	13.7	58	-2.4	2.06	2.14	$2.65	19.000	14.125	14.24
Central Illinois Light	41	24.6	55	10.0	94	-11.4	3.92	3.02	$2.80	19.375	13.625	5.15
Philadelphia Electric	42	24.5	66	8.7	11	4.6	2.28	1.90	$2.39	17.125	13.000	10.30
Niagara Mohawk Power	43	23.9	49	11.3	1	29.1	1.97	1.67	$2.64	16.875	11.875	15.84
Washington Water Power	44	23.6	61	9.2	89	-6.4	2.78	2.63	$3.17	21.500	17.125	10.92
Virginia Electric & Power	45	22.7	60	9.2	30	0.2	1.59	1.19	$1.98	15.125	11.125	-2.25
Central Hudson Gas & Electric	46	22.1	86	0.2	93	-8.9	1.99	1.90	$3.91	24.750	17.125	18.55
Interstate Power	47	22.1	67	8.1	27	0.6	2.60	2.32	$2.46	16.250	10.875	0.29
Utah Power & Light	48	21.8	16	17.8	4	14.4	2.13	2.17	$2.38	22.375	17.250	12.22
Central Vermont Public Service	49	21.5	35	13.9	6	10.4	4.01	3.66	$3.79	22.750	15.500	1.33
Allegheny Power System	50	21.3	63	9.0	85	-5.2	2.70	2.31	$3.41	24.500	16.125	8.04
Duke Power	51	20.7	17	17.6	76	-4.0	2.12	1.89	$3.59	24.000	20.375	6.55
Kansas Power & Light	52	20.6	19	17.4	32	0.0	3.00	3.83	$3.60	24.875	17.625	17.23
Public Service of New Hampshire	53	19.7	94	-4.0	34	-0.1	1.86	1.64	$2.73	18.250	12.750	41.80
Minnesota Power	54	19.7	89	-1.3	98	-18.2	2.32	2.48	$3.51	24.375	17.500	6.31
Texas Utilities	55	19.3	14	18.2	14	3.4	2.30	2.50	$3.85	25.750	19.125	9.56
Iowa-Illinois Gas & Electric	56	19.2	36	13.9	84	-5.2	2.13	2.24	$3.95	23.375	17.750	6.40
Baltimore Gas & Electric	57	19.1	44	12.3	46	-1.7	2.35	2.24	$4.07	30.375	22.750	-0.56
New England Electric System	58	19.1	97	-5.4	41	-1.2	2.31	1.98	$4.65	33.500	23.875	0.15
Wisconsin Power & Light	59	18.9	41	12.8	54	-2.1	3.40	2.93	$3.51	29.500	19.125	0.54
Public Service of Colorado	60	18.7	12	19.0	35	-0.3	2.62	2.38	$2.17	17.625	13.375	2.97
Iowa Electric Light & Power	61	16.2	23	16.6	15	3.3	1.64	1.34	$2.19	16.375	12.000	-1.27
Montana Power	62	15.9	83	1.5	49	-1.8	1.91	2.15	$3.97	27.250	21.625	40.37
Arizona Public Service	63	15.0	10	20.7	72	-3.3	2.52	1.85	$3.30	25.125	18.000	8.26
Pennsylvania Power & Light	64	15.0	70	7.6	64	-2.9	1.08	1.03	$3.35	21.875	16.500	7.29
Southern California Edison	65	14.5	74	6.1	81	-5.0	1.50	1.86	$5.13	37.125	28.000	12.87
Pacific Power & Light	66	14.5	62	9.1	17	2.7	1.41	1.04	$3.03	21.875	16.250	1.50
Central & South West	67	14.5	34	14.0	66	-3.0	2.29	2.26	$2.82	18.750	13.250	4.93
Hawaiian Electric	68	14.5	81	3.3	47	-1.7	1.72	1.64	$4.10	30.625	23.625	-1.84
Commonwealth Energy Systems	69	14.4	69	7.7	36	-0.6	2.11	1.78	$2.45	19.000	13.000	-1.90
Iowa Resources	70	13.8	18	17.6	24	1.1	2.58	2.10	$3.66	27.000	21.250	14.54
Carolina Power & Light	71	13.4	32	14.5	33	0.0	2.01	1.82	$3.17	23.000	18.875	1.37
Toledo Edison	72	12.7	64	8.9	71	-3.3	1.39	1.33	$3.18	21.130	15.750	15.86
Orange & Rockland	73	12.4	40	12.8	28	0.4	2.81	2.19	$2.59	19.000	13.375	-1.69
Consumers Power	74	11.8	87	0.0	77	-4.2	1.23	1.22	$3.16	20.000	16.250	22.59
Consolidated Edison	75	11.2	78	4.1	48	-1.8	4.25	3.71	$3.55	21.125	15.438	4.53
Ohio Edison	76	10.7	46	11.7	60	-2.6	0.82	0.90	$2.13	15.125	11.375	13.96
Tampa Electric	77	10.6	100	-7.1	90	-7.3	2.41	2.49	$2.75	21.875	17.625	10.69
Middle South Utilities	78	10.3	75	4.7	68	-3.0	0.86	0.89	$2.33	15.875	12.250	13.68
Potomac Electric Power	79	10.0	58	9.5	19	2.1	2.19	2.16	$2.28	18.750	13.750	14.09
Duquesne Light	80	9.6	99	-6.3	99	-19.0	1.21	1.28	$1.96	16.375	12.750	3.99
Central Illinois Public Service	81	9.3	52	10.9	18	2.5	4.10	3.83	$1.81	15.750	10.875	-4.81
Rochester Gas & Electric	82	7.8	50	11.1	80	-4.7	1.98	2.44	$2.81	17.125	12.500	6.40
Wisconsin Public Service	83	7.3	13	18.7	29	0.2	2.78	3.51	$3.14	25.250	17.750	-14.94
Gulf State Utilities	84	5.4	72	7.0	82	-5.1	1.13	1.09	$1.95	14.000	11.125	8.74
Public Service of New Mexico	85	4.2	3	26.9	5	12.7	2.03	2.41	$3.22	28.125	21.625	14.73
Southern Indiana Gas & Electric	86	4.1	77	4.3	96	-15.4	2.90	3.13	$3.42	25.500	18.625	-0.01
Detroit Edison	87	2.6	80	3.4	86	-6.0	0.89	0.89	$1.75	13.750	11.000	16.87
Central Louisiana Electric	88	1.2	71	7.6	100	-24.7	1.47	1.19	$2.47	15.500	12.750	-42.76
Portland General Electric	89	-1.9	79	-3.8	61	-2.6	2.13	1.71	$2.38	16.250	11.875	-4.91
Louisville Gas & Electric	90	-3.0	93	13.2	75	-3.6	1.77	2.32	$2.21	22.625	17.375	16.99
Kansas City Power & Light	91	-4.1	38	2.1	67	-3.0	1.66	1.79	$4.18	28.125	21.750	10.66
Puget Sound Power & Light	92	-7.3	82	14.4	9	5.0	1.51	1.58	$2.29	15.875	12.500	14.02
American Electric Power	93	-9.0	33	-0.3	95	-13.7	1.17	1.24	$2.03	19.750	15.875	4.22
Missouri Public Service	94	-11.9	88	12.7	26	0.7	2.05	1.76	$2.10	16.125	10.125	-7.79
Florida Power Corporation	95	-15.2	42	-5.3	74	-3.6	1.45	2.20	$2.20	19.500	14.875	15.59
Boston Edison	96	-21.5	96	1.1	31	0.1	1.24	1.58	$3.18	26.125	20.000	0.24
Atlantic Electric	97	-29.6	84	-5.4	43	-1.5	1.27	1.84	$1.84	21.375	16.750	4.06
Savannah Electric & Power	98	-35.2	98	0.4	78	-4.3	0.70	1.21	$1.40	13.875	9.875	15.57
Houston Lighting & Power	99	-45.7	85	25.6	37	-0.6	1.37	3.05	$1.62	21.625	17.500	8.31
Centel (Electric properties only)	100	N/A	4	4.1	88	-6.4	N/A	N/A	N/A	N/A	N/A	N/A

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ALPHABETICAL LISTING OF COMPANY PERFORMANCES

	Electric Sales		Customers Served				Revenues			
			Electric		Gas					
Company	Rank	KWH Sales (millions)	Total (1,000's)	% Gain	Total (1,000's)	% Gain	Total (1,000's)	% Electric	% Gas	Net Income After Tax (1,000's)
Allegheny Power System	12	42,246	1,147	0.86	0	0.00	$1,751,811	100.00	0.00	$160,668
American Electric Power	1	97,535	2,518	0.29	70	1.98	$4,179,955	96.63	2.36	$335,027
Arizona Public Service	45	12,951	449	2.37	339	−0.51	$1,064,453	81.40	18.60	$196,227
Atlantic Electric	76	5,592	370	1.10	0	0.00	$ 444,178	100.00	0.00	$ 27,761
Baltimore Gas & Electric	32	17,292	859	1.28	513	0.12	$1,595,471	64.91	33.81	$146,836
Boston Edison	47	12,030	615	0.75	0	0.00	$1,056,267	93.67	0.00	$ 45,882
Carolina Power & Light	17	30,483	772	1.91	0	0.00	$1,538,165	100.00	0.00	$182,542
Centel (Electric properties only)	94	2,333	133	0.79	0	0.00	$ 144,443	99.30	0.00	N/A
Central & South West	11	46,437	1,419	2.77	0	0.00	$2,389,253	98.26	1.74	$234,131
Central Hudson Gas & Electric	79	5,028	217	1.69	47	1.95	$ 445,809	86.17	13.83	$ 31,203
Central Illinois Light	83	4,187	184	−0.79	184	−0.31	$ 480,508	58.93	41.07	$ 34,825
Central Illinois Public Service	58	8,591	305	0.24	150	1.91	$ 587,083	76.43	23.57	$ 56,753
Central Louisiana Electric	80	5,019	184	2.00	0	0.00	$ 280,382	97.92	0.00	$ 23,319
Central Maine Power	68	6,662	401	3.27	0	0.00	$ 405,289	99.02	0.00	$ 33,563
Central Vermont Public Service	97	2,333	115	0.77	0	0.00	$ 133,663	98.52	0.00	$ 13,807
Cincinnati Gas & Electric	41	14,471	600	0.49	366	−0.20	$1,260,507	62.29	37.71	$105,702
Cleveland Electric Illuminating	38	16,165	711	−0.01	0	0.00	$1,108,572	98.42	0.00	$170,669
Commonwealth Edison	6	59,225	2,971	0.13	0	0.00	$4,129,666	100.00	0.00	$506,420
Commonwealth Energy Systems	78	5,274	278	0.94	200	0.76	$ 607,081	59.61	38.05	$ 19,863
Consolidated Edison	18	29,760	2,759	0.73	1,017	0.01	$5,067,404	79.16	13.68	$452,969
Consumers Power	24	24,612	1,344	0.40	1,168	0.77	$2,731,081	52.77	44.75	$202,785
Dayton Power & Light	55	10,037	421	0.11	264	−0.23	$ 886,648	68.36	30.69	$ 93,160
Delmarva Power & Light	62	7,249	292	1.81	75	0.79	$ 636,666	84.00	13.31	$ 60,753
Detroit Edison	15	31,995	1,763	−0.24	0	0.00	$2,123,254	97.91	0.00	$181,456
Duke Power	9	51,380	1,322	1.19	0	0.00	$2,244,480	100.00	0.00	$336,017
Duquesne Light	50	11,038	557	0.24	0	0.00	$ 746,462	99.19	0.00	$ 94,181
Eastern Utilities Associates	86	4,049	230	0.97	0	0.00	$ 288,417	96.27	0.00	$ 16,941
El Paso Electric	89	3,651	190	2.17	0	0.00	$ 270,090	99.65	0.00	$ 63,813
Empire District Electric	95	2,436	101	0.96	0	0.00	$ 105,378	99.57	0.00	$ 9,541
Florida Power & Light	10	47,073	2,403	2.86	0	0.00	$2,940,833	100.00	0.00	$263,708
Florida Power Corporation	30	18,761	853	3.46	0	0.00	$1,210,513	99.74	0.00	$ 80,628
General Public Utilities	16	31,353	1,611	−17.72	0	0.00	$2,405,527	99.85	0.00	$ 33,734
Gulf State Utilities	22	26,389	530	2.50	85	−0.32	$1,307,259	90.95	3.30	$127,030
Hawaiian Electric	72	6,094	293	2.28	0	0.00	$ 687,328	99.88	0.00	$ 29,740
Houston Lighting & Power	7	56,529	1,209	8.16	0	0.00	$3,478,808	100.00	0.00	$122,248
Idaho Power	42	14,178	261	1.39	0	0.00	$ 367,794	100.00	0.00	$ 66,778
Illinois Power	43	13,978	526	0.16	383	−0.10	$1,106,775	61.94	38.06	$136,498
Indianapolis Power & Light	57	8,880	335	0.97	0	0.00	$ 397,594	94.31	0.00	$ 51,648
Interstate Power	85	4,074	155	−0.16	45	−0.52	$ 280,958	70.32	29.68	$ 20,149
Iowa Electric Light & Power	84	4,100	204	0.14	132	0.27	$ 402,847	61.29	36.97	$ 22,623
Iowa-Illinois Gas & Electric	87	3,854	175	0.49	224	0.03	$ 474,633	43.63	56.37	$ 44,799
Iowa Resources	82	4,216	231	0.25	133	0.02	$ 385,931	62.28	36.86	$ 35,421
Iowa Public Service	93	3,025	159	−0.20	122	−0.50	$ 370,524	56.78	43.13	$ 29,513
Kansas City Power & Light	59	8,072	351	0.51	0	0.00	$ 475,802	100.00	0.00	$ 62,748
Kansas Gas & Electric	63	7,238	235	0.66	0	0.00	$ 350,937	99.68	0.00	$ 70,521
Kansas Power & Light	69	6,636	280	0.87	133	0.60	$ 481,519	69.01	30.99	$ 56,310
Kentucky Utilities	53	10,316	368	0.88	0	0.00	$ 476,783	99.56	0.00	$ 44,308
Long Island Lighting	44	13,071	916	0.81	399	0.63	$1,633,517	80.84	19.16	$249,405
Louisville Gas & Electric	61	7,386	297	0.32	233	−0.09	$ 560,038	62.20	37.64	$ 33,708
Madison Gas & Electric	99	1,940	100	1.12	69	1.16	$ 189,204	55.79	43.91	$ 12,114
Middle South Utilities	8	51,400	1,587	1.06	242	0.21	$2,901,730	92.14	5.95	$310,595
Minnesota Power	64	7,033	115	−0.17	9	0.00	$ 364,394	96.54	3.00	$ 41,808
Missouri Public Service	96	2,413	135	0.69	40	−1.18	$ 187,512	78.79	20.73	$ 12,411
Montana-Dakota Utilities	100	1,776	113	1.99	175	2.56	$ 422,467	24.13	59.93	$ 31,299
Montana Power	60	7,654	232	1.33	102	−0.51	$ 497,589	39.70	33.21	$ 62,202
Nevada Power	75	5,753	205	3.11	0	0.00	$ 286,543	100.00	0.00	$ 38,642
New England Electric System	36	16,388	1,086	1.34	0	0.00	$1,212,649	98.31	0.00	$108,325
New York State Electric & Gas	51	10,733	676	0.75	130	0.42	$ 889,223	79.20	20.80	$122,485
Niagara Mohawk Power	14	32,640	1,380	1.40	431	0.70	$2,393,771	77.73	22.27	$230,948
Northeast Utilities	29	19,591	1,091	1.04	154	1.18	$1,763,220	86.33	12.73	$151,242
Northern Indiana Public Service	48	11,964	359	−0.43	529	0.40	$1,732,728	45.13	54.87	$ 81,151
Northern States Power	21	26,777	1,155	5.02	291	5.32	$1,560,916	75.48	23.91	$144,041
Ohio Edison	26	24,025	965	0.21	0	0.00	$1,429,626	100.00	0.00	$181,496
Oklahoma Gas & Electric	28	20,922	606	2.47	0	0.00	$ 907,561	100.00	0.00	$ 93,173
Orange & Rockland	92	3,476	211	1.26	90	1.70	$ 479,357	72.15	27.49	$ 34,126
Otter Tail Power	90	3,601	121	0.33	0	0.00	$ 157,602	100.00	0.00	$ 15,099
Pacific Gas & Electric	3	60,446	3,546	0.88	2,915	0.60	$6,785,095	56.72	43.28	$657,624
Pacific Power & Light	23	24,728	658	0.79	0	0.00	$1,405,798	56.14	0.00	$157,074
Pennsylvania Power & Light	27	22,297	1,014	0.70	0	0.00	$1,219,548	99.49	0.00	$210,572
Philadelphia Electric	19	29,561	1,332	0.60	298	1.65	$2,644,753	82.46	14.76	$278,623
Portland General Electric	40	14,907	508	1.17	0	0.00	$ 572,193	100.00	0.00	$ 97,050
Potomac Electric Power	35	17,117	532	1.85	0	0.00	$1,095,153	99.66	0.00	$102,629
Public Service of Colorado	39	15,433	865	2.23	718	2.44	$1,590,039	53.04	46.06	$ 99,835
Public Service of Indiana	31	17,635	542	0.18	0	0.00	$ 809,394	98.75	0.00	$205,222
Public Service of New Hampshire	73	6,068	293	1.22	0	0.00	$ 423,290	99.04	0.00	$ 69,470
Public Service of New Mexico	70	6,491	222	2.27	0	0.00	$ 426,543	98.50	0.00	$ 91,760
Public Service Electric & Gas	20	29,146	1,705	0.69	1,320	0.76	$3,873,976	65.65	34.35	$288,962
Puget Sound Power & Light	37	16,183	571	1.75	0	0.00	$ 467,697	100.00	0.00	$ 77,940
Rochester Gas & Electric	71	6,369	293	1.13	230	1.07	$ 681,913	59.49	37.14	$ 59,502
San Diego Gas & Electric	52	10,529	805	1.53	520	1.26	$1,430,948	79.52	20.48	$131,235
Savannah Electric & Power	98	2,194	92	1.91	0	0.00	$ 136,164	99.76	0.00	$ 5,769
Sierra Pacific Power	88	3,830	187	7.34	54	1.49	$ 325,530	79.89	15.40	$ 32,257
South Carolina Electric & Gas	49	11,490	357	1.74	186	10.08	$ 859,036	68.69	31.01	$ 79,750
Southern California Edison	5	59,327	3,275	1.31	1	0.33	$4,303,577	99.98	0.02	$483,358
Southern Company	2	96,787	2,659	1.52	0	0.00	$4,927,183	99.07	0.00	$472,331
Southern Indiana Gas & Electric	91	3,600	104	0.46	63	0.79	$ 229,761	65.80	32.38	$ 18,556
Southwestern Public Service	46	12,864	312	2.29	0	0.00	$ 637,181	99.59	0.00	$ 77,583
Tampa Electric	54	10,038	350	3.18	0	0.00	$ 573,761	99.44	0.00	$ 47,852
Texas-New Mexico Power	77	5,336	175	3.00	0	0.00	$ 342,010	99.96	0.00	$ 8,848
Texas Utilities	4	60,380	1,696	4.07	0	0.00	$3,238,025	98.23	0.00	$428,646
Toledo Edison	66	6,918	269	−0.10	5	0.23	$ 481,725	98.23	1.23	$ 79,313
Tucson Electric Power	74	5,964	202	2.32	0	0.00	$ 457,801	75.09	0.00	$180,936
Union Electric	25	24,097	988	0.13	107	−0.99	$1,217,705	91.31	7.41	$165,506
United Illuminating	81	4,475	285	0.60	0	0.00	$ 436,730	99.51	0.00	$ 51,671
Utah Power & Light	34	17,241	469	1.96	0	0.00	$ 782,070	99.87	0.00	$112,507
Virginia Electric & Power	13	39,980	1,405	1.76	123	1.65	$2,360,770	95.50	4.50	$221,598
Washington Water Power	56	8,995	228	0.77	76	0.17	$ 346,853	59.20	38.89	$ 48,777
Wisconsin Electric Power	33	17,280	819	0.74	218	1.14	$1,302,910	74.82	24.35	$116,558
Wisconsin Power & Light	65	6,970	307	0.79	103	1.15	$ 512,477	72.37	27.00	$ 42,256
Wisconsin Public Service	67	6,810	289	1.13	153	0.82	$ 584,447	60.87	39.13	$ 36,871

the humdrum revenue gain and decrease in kWh sales and is a testimonial to the cost control efforts of most utility top managements.

As was discussed above, the substantial net income growth tends to mask the true erosion of financial strength that has resulted from inclusion of large amounts of AFUDC.

Median net income change was 11.1 percent in 1982, less than half what it was in 1981 (22.6 percent). Overall, 86 utilities reported increases.

The per-share earnings performance of the Top 100 Electric Utilities improved again in 1982, rising to an average of $3.00 per share. This represents a 6.4 percent increase in average per-share earnings from the $2.82 reported a year ago.

TABLE III
THE TOP 10 INCOME PRODUCERS

(Net After-Tax Available for Common)

Rank				
'82	'81	Company	Income (millions)	'82 % Change
1	1	Pacific Gas & Electric	$657.6	52.6
2	6	Commonwealth Edison	$506.4	43.9
3	2	Southern California Edison	$483.4	14.5
4	7	Southern Company	$472.3	44.9
5	3	Consolidated Edison	$453.0	11.2
6	5	Texas Utilities	$428.6	19.3
7	9	Duke Power	$336.0	20.7
8	4	American Electric Power	$335.0	−9.0
9	8	Middle South Utilities	$310.6	10.3
10	12	Public Service Electric & Gas	$289.0	35.9

It must be pointed out, however, that even with this year's 6.4 percent gain coming on the heels of last year's 11.9 percent increase, the total gain since 1972 is only 48 cents per share. This means that the 11-year increase in earnings per-share amounts to 19 percent or an average of about 1.7 percent in current dollars.

Clearly, one must reflect that 1982 was a *better* year, but…

In 1982, 77 utilities reported increases in share earnings from the previous year, while 22 reported declines. This represents a small improvement from 1981, when 72 companies reported increases and 26 declines.

For the 99 companies providing earnings data, the median rate of change was 10.15 percent, fractionally lower than last year's 10.38 percent, but well above the 2.85 percent and 1.97 percent reported in 1980 and 1979, respectively.

As is common when ranking performances on the basis of rate-of-change, the majority of companies recording the largest increases in share earnings were those coming off poor earnings performances the previous year. Twelve of the companies ranking in the top 25 this year were in the bottom 25 a year ago, three ranked in the third 25 in 1981 and three ranked in the second 25. Seven companies in the top 25 were in the top 25 a year ago, which is substantially better than earlier years.

Three companies reported declines in share earnings in 1982 for the second straight year. They were TECO Energy (Tampa Electric's parent) down 8.33 percent to $2.75; American Electric Power, down 14.35 percent to $2.05 and Louisville Gas & Electric, off 18.45 percent to $2.21.

On the up-side, however, General Public Utilities reported an earnings gain of 66.7 percent, reversing four straight years of earnings declines.

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Study finds declining construction leadtimes for nukes being built

Robert Smock
Managing Editor

A new EPRI study challenges some common assumptions about the nature of delay in nuclear plant construction. Shown is a 1981 photo of construction at WNP-4 now cancelled.

A new study published by the Electric Power Research Institute shows that nuclear plant construction leadtimes are decreasing for plants now being built. That finding sharply contradicts other studies of nuclear construction which show that leadtimes have steadily increased to a current average of about 10 years.

The study, titled, "An Analysis of Power Plant Construction Lead Times," was done by Applied Decision Analysis, Inc., a Menlo Park, California consulting firm. It's must reading for any utility manager thinking about the possibility of ordering new nuclear capacity and concerned about the unpredictability of the length and cost of construction.

Several unusual analytical methods led to the surprising findings. First, the researchers plotted construction leadtime (defined as the time from construction permit issuance to fuel load approval) against year of CP issuance, not year of completion. The reasoning was that the CP date more accurately represents the "regulatory era" of a plant than the completion date.

Also, the researchers eliminated the effects of deliberate delays imposed by management and the effects of physical plant differences, differences in construction management approach, etc. which can cause considerable variation in leadtime but do not explain the trend over time.

The result was the two-part trendline shown in the figure. The solid line on the left shows the leadtime trend for plants with CPs issued from 1966 to 1971. These are the post-turnkey, pre-Calvert-Cliffs-decision plants. They are, essentially, the nuclear plants now in operation. Normalizing out the data-scatter effects and factoring out deliberate delay leaves a straight line increasing at a rate of 4 to 5 percent a year. Construction leadtimes for plants issued CPs during that period increased from roughly 60 months to about 80 months.

A discontinuous leap up to about 125 months for plants issued CPs in 1972 and the years immediately following is shown in the second part of the trend line. These are the plants just now being completed and, for the most part, still under construction.

The completion dates for most of these plants had to be calculated since most are unfinished. The researchers used utility estimates as an input to a model they constructed to forecast completion dates. The model predicts a steady decline from the 125-month level back down to the trend line.

Where will it go from there? "We deliberately tried not to speculate," says EPRI project manager Steve Chapel.

Why the jump

The reason for the discontinuity—and the major lesson to be learned from the study—is the regulatory era encountered by plants issued CPs just after 1972.

Those plants were particularly vulnerable to the regulatory-ratchet aftereffects of the three major nuclear industry shocks of the 1970s: the 1971 Calvert Cliffs decision, the 1975 Browns Ferry fire, and the 1979 accident at Three Mile Island.

They were hit at the front end of their construction cycle by the Calvert Cliffs court decision which forced the AEC (the NRC's regulatory predecessor) to conduct elaborate environmental analyses of nuclear projects instead of the perfunctory checks they had been doing. The study says that added a year between the CP date and the first concrete pour for the first projects affected. (Prior to that, says the study, it was possible to begin construction before the CP was officially obtained.) Then the Browns Ferry fire spawned a rash of construction fire-prevention backfits and new procedures. Finally, the TMI accident caught many of these vulnerable projects during the closing phases of their construction, paralyzing activity while the regulatory lessons learned from the accident were digested.

The study cites three examples of completed, post-'72-CP plants to illustrate the leadtime decline: LaSalle 1 got its CP in September, 1973 and took 104 months to reach the fuel-load date; San Onofre 2 got a CP in October, 1973 and took 100 months; and Grand Gulf 1 got a CP in September, 1974 and took 93 months. (Not mentioned in the study is the surprising record achieved at St. Lucie 2 which got its CP in 1977. It recently started after a leadtime of only 70 months.)

Plants with CPs issued after 1976 are not being delayed as much by these effects, the study suggests. It forecasts that they will be completed in the 7- to 8-year time frame consistent with the long term trendline.

Fundamental reform needed

That trendline, however, shown as a dotted line on the chart, is upward. It suggests that construction leadtimes for plants ordered in the future will not continue to decline, but will increase due to the underlying regulatory ratchet effect.

Says the study, "The impact of industry-wide shocks is abating, but extensive out-of-scope work caused by normal regulations persists."

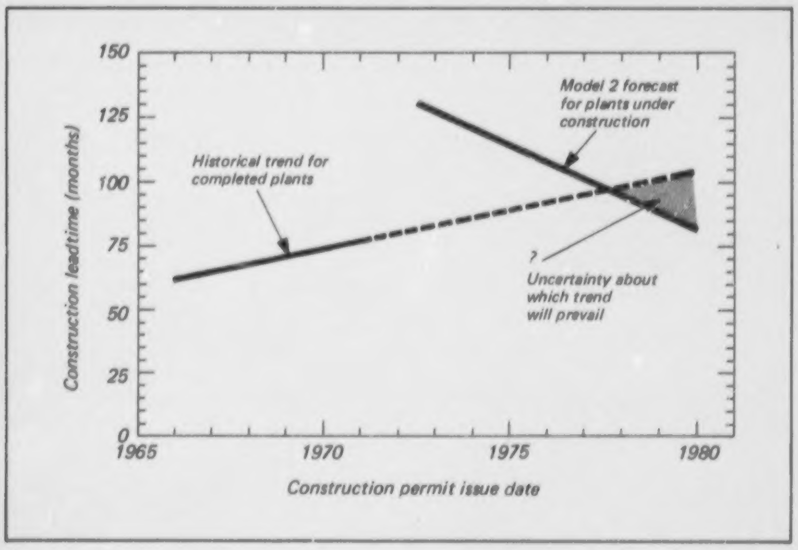
Is the continued increase inevitable? "On average, the industry-wide increase in leadtimes appears to be controllable only through fundamental alteration of the regulatory process. Without such change, leadtimes will probably remain the same or even continue to grow, if and when new plants are licensed."

Root causes of delay

Another of the major contributions of the study is its identification of the major root causes of delay. As shown in the figure, the underlying regulatory ratchet effect was identified as causing 50 percent of all construction leadtime delay. The other major root causes were labor material delivery problems (20 percent) and deliberate delay (22 percent.)

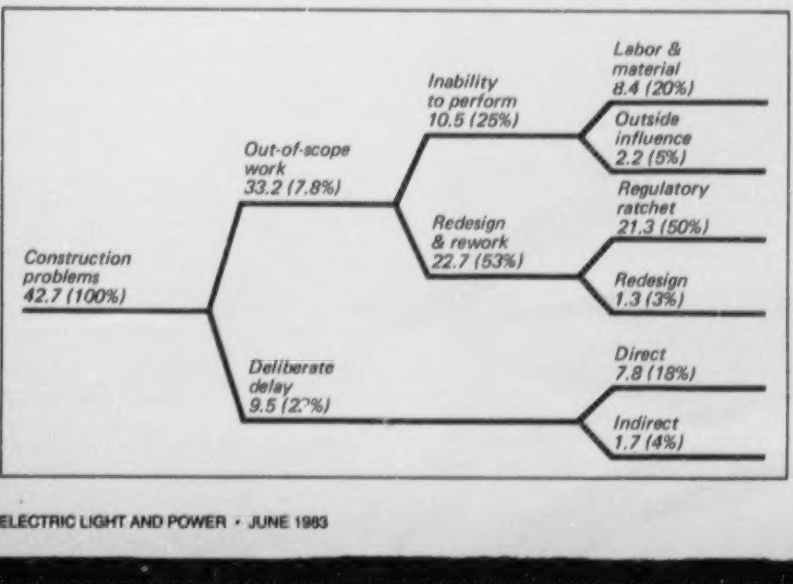
These root causes were unearthed through an in-depth investigation of construction at 26 nuclear projects in both categories (pre- and post-1972

Continued on next page



A plot of construction leadtimes against CP date for nuclear plants shows a two-part trendline.

Root causes of delay (in months) are identified for the average nuclear construction project.


Construction problems 42.7 (100%)
Out-of-scope work 33.2 (7.8%)
Inability to perform 10.5 (25%)
Labor & material 8.4 (20%)
Outside influence 2.2 (5%)
Redesign & rework 22.7 (53%)
Regulatory ratchet 21.3 (50%)
Redesign 1.3 (3%)
Deliberate delay 9.5 (22%)
Direct 7.8 (18%)
Indirect 1.7 (4%)

LILCO tries coating to slow superheater exfoliation

CHICAGO—The first full-scale demonstration of a pioneering boiler corrosion-control process is currently underway at Long Island Lighting Co.'s Glenwood station. The retrofit application was described at the American Power Conference in a paper by Foster Wheeler, which developed the process, EPRI, which helped fund the demonstration, and LILCO.

The process is based on coating the inside of superheater tubes with a chromate material that makes ferritic steel behave like stainless. It's intended to reduce the exfoliation of scale out of the superheater, a major cause of turbine blade erosion in many power plants.

The paper claims that this is the only process available for retrofitting to superheaters that have seen considerable service. (Glenwood is an early '50s vintage station.) The chromate compound is designed to alter the surface chemistry of the steel to produce a stable scale that's strongly bonded to the tube and won't exfoliate. The authors reported that the coating also retards scale growth by a factor of three.

Small-scale tests dating back to 1979 have shown that the concept works, according to the paper. Side-by-side tests at Con Ed's Astoria 4, for example, showed that after two years there was no exfoliation from 180 ft of treated superheater tubes in the finishing superheater while there was substantial exfoliation from untreated tubes.

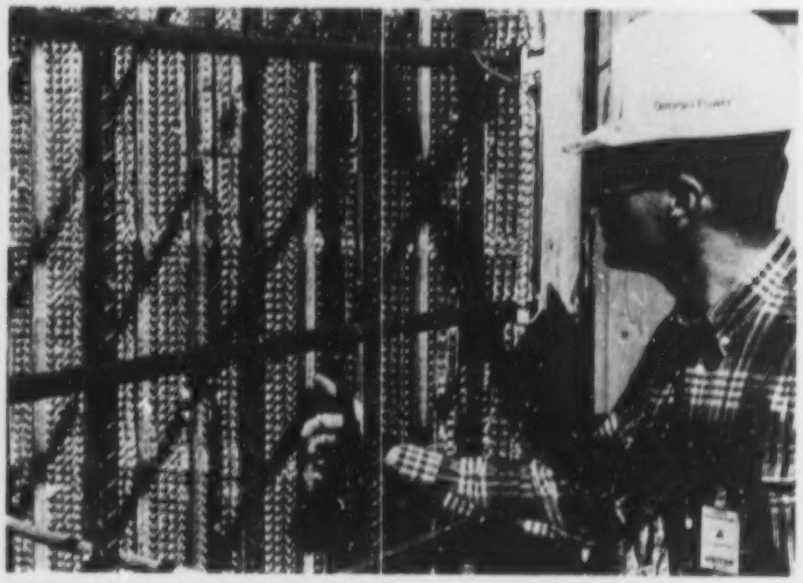
In the full-scale demonstration at LILCO, application of the coating was designed as a supplement to chemical cleaning of the tubes, using the same piping and connections.

The tubes were cleaned with Vertan 675, a high temperature chelating solvent. After flushing and hydrotesting the chromate was pumped through. It was injected through the main steam stop valve and circulated in reverse through the superheater and steam drum and out the boiler drains and downcomers to the pump suction line. The coating was pumped through under high pressure, 800-900 psi, and at temperatures above 500F.

Examination of samples after the treatment show it was effectively applied, the researchers reported. A "dense, bonded, oxide layer" similar to that observed on laboratory samples had formed on the inside of the boiler sample.

Concluded the authors, "The effective life of the chromate-treated superheater tubes, before exfoliation, will be observed by evaluating them in future years. Based on laboratory test data, we anticipate a minimum 15-year service life for tubes before any significant exfolation occurs."

Cuts concrete-pouring labor costs 25%



Georgia Power is reducing labor costs in concrete pouring at its Vogtle nuclear project through use of a steel mesh bulkhead. The mesh is used at joints instead of plywood forms, eliminating the time-consuming stripping and cleaning of the plywood since the mesh is left in the concrete. The mesh supplier, Expanded Metal Corp. of Marietta, Georgia, says that wet concrete flows through the mesh, creating a surface that's ready for the next pour with no preparation. The utility has purchased more than 100,000 sq ft of the mesh so far for the construction project. The supplier says costs for installation and materials have been cut 40 percent via use of the product, and labor costs have been cut 25 percent.

PWR SG cleaning process developed

RICHLAND, WA—A new process has been developed for chemically cleaning steam generators in pressurized water reactor nulcear plants, reported UNC Nuclear Industries here. The process, intended to reduce tube denting, was a joint development of EPRI and the Steam Generator Owners Group.

It features solvents that dissolve metallic copper, copper oxide deposits, and magnetite without attacking the underlying carbon steel or Inconel tube material.

Leadtimes . . . from page 43

The root-cause analysis shows the true significance of deliberate delay. It reveals that it's a major factor in a few projects. Of the 26 studied in depth only eight had significant deliberate delays. For those eight, however, deliberate delay accounted for 38 percent of total delay, or an average of 29 months per project. For the other 18, deliberate delay accounted for only 6 percent, or two months of total delay. An overall average that includes the delay factor can, therefore, mask the real trends.

Key reasons identified for deliberate delay were load growth lower than predicted and financial strain on the utility during construction.

The other major branch on the root-cause tree is out-of-scope work caused by traditional problems with labor and materials and by the nuclear regulatory agency. The CP-date analysis shows how variable the regulatory ratchet effect can be—how it is a function of the "regulatory era" in which the plant is built.

The study shows that there has been no increase in leadtimes for fossil power plants: "The long term historical trend is flat. When allowance is made for deliberate delays, virtually no growth in construction leadtimes can be indentified."

As with the nuclear plants, the study included an in-depth analysis of 28 fossil construction projects. It showed, on average, only 10 months of delay (in contrast to the 43 months encountered at the average nuclear project.) Of that 10 months, 7 months could be accounted for by deliberate delays by management.

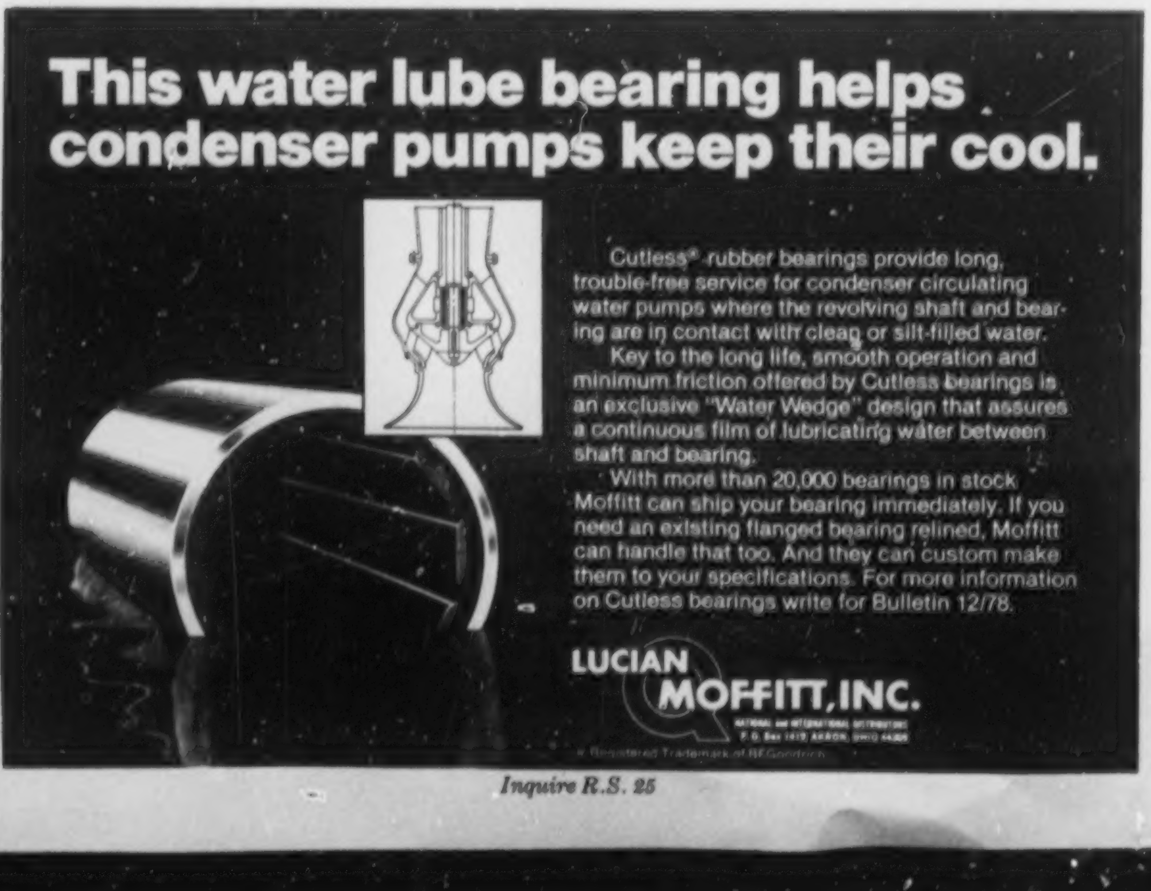
"Since leadtimes (for fossil plants) have not changed substantially over time, the question of controlling them is moot," says the study. "It appears that the industry has been able to compensate prior to the start of construction, at least with respect to leadtimes, to the increased environmental regulatory requirements imposed during the past 15 years. As for the leadtime increase observed when deliberate delays are included, if load growth forecasts become more accurate and the funds required to undertake major construction projects become less constrained, then there will likely be no growth whatsoever, on the average, in leadtimes for coal power plants."

Remaining variations in construction time for different nuclear projects can be explained by differences in plant physical characteristics, project management methods, and uncontrollable events, says the study. EPRI's Steve Chapel says that Volume 2 of the study is due soon and will describe these differences in detail.

However, these factors do not explain trends; they explain data scatter. They are factors associated with construction length variations that have been analyzed in previous studies, and the findings of the new study are consistent.

For example, the study found that these factors influence construction length: unit capacity, A/E experience, region, cooling towers, plant multiplicity nature of project, and whether or not it has a B&W NSSS. The study added the "regulatory era" effect to these well-known factors to explain the trend.

Interestingly, the study found no correlation to construction length with the utility's financial condition, accuracy of load growth estimation, and state regulatory environment.



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U.S. Supreme Court upholds FERC rules on avoided costs, power interconnections with cogenerators

WASHINGTON, D.C.—The Federal Energy Regulatory Commission was fully within is legislative authority when it promulgated rules for co-generators and small power producers regarding how the purchase price for electricity should be set and under what circumstances monopolistic electric companies are required to interconnect with small qualified power facilities.

This was the conclusion of the U.S. Supreme Court that found FERC's avoided cost and interconnection rules had been formulated in accordance with the Public Utilities Regulatory Policy Act (PURPA) of 1978.

The decision overturned a contrary interpretation of the U.S. Appeals Court for the Washington, D.C. circuit.

A cogeneration facility is defined as one that produces both electricity and steam (or some other form of useful energy, such as heat). A small power production facility is defined as having a capacity of not more than 80 megawatts and produces electric power from biomass, waste, or renewable resources such as wind, water, or solar energy.

Following rulemaking proceedings, FERC had promulgated a rule requiring utilities to purchase electric energy from a qualifying co-generation or small power production facility at a rate equal to the utility's "full avoided cost,"—the cost to the utility which, except for the purchase from the qualifying facility, would be incurred by the utility in generating the electricity itself or purchasing the electricity from another source.

FERC had also promulgated a rule requiring utilities to make such physical interconnections with qualifying facilities as were considered to be necessary to accomplish the sales and purchases of electricity authorized under PURPA.

Upon review, the Court of Appeals had vacated both rules, holding that FERC had not adequately explained its adoption of the full avoided cost rule, and had exceeded its statutory authority in promulgating the interconnection rule.

Is 'avoided cost' just?

In examining whether FERC avoided cost rule was in accordance with Congressional intent as expressed in the PURPA legislation, the Supreme Court asked whether the rule was just and reasonable to electricity consumers and the public interest.

The High Court rejected the arguments of respondents that "just and reasonable" was intended to require the utility purchase price be set "at the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest."

"Simply on the basis of the statutory language," Justice Marshall wrote in his opinion for the Court, "we would be reluctant to infer that Congress intended the terms 'just and reasonable'... to adopt a cost of service approach in the very different context of cogeneration and small power production by nontraditional facilities.

"The legislative history confirms, moreover, that Congress did not intend to impose traditional ratemaking concepts on sales by qualifying facilities to utilities."

The Court said that FERC would

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Cool Water plant gets SFC aid

Construction continues at the Cool Water Coal Gasification Plant site in Daggett, California. The U.S. Synthetic Fuels Corporation recently signed a letter of intent to provide $120 million in price support for the program. Designed and being constructed by Bechtel Corp., the $284 million project is expected to be completed in mid-1984.

APPA chief challenges conventional supply estimates; plant sizes hit

Dan Utroska
Associate Editor

WASHINGTON, D.C.—The executive director of the American Public Power Association has challenged electric industry demand and supply projections, coming up with figures that measurably contravene estimates put forward by such groups as the Department of Energy, the Edison Electric Institute, and the North American Electric Reliability Council.

In addition, APPA's Alex Radin has recommended that smaller-sized power plants are best for meeting future marginal electricity demand.

Radin's remarks before attendees at the Americans for Energy Independence Conference here are seminal in what they suggest on a broader front: that now a major segment of the electric utility industry, namely the public power sector, is seen nominally aligning itself with such groups as the Environmental Defense Fund and the Energy Productivity Center at the Mellon Institute as far as electricity demand and supply projections are concerned.

"We more closely identify with that school of thought than with that of Edison Electric Institute or the Department of Energy," Radin told *EL&P*.

Stressing that he still believed there would be demand growth, Radin said, "Frankly, the WPPSS situation is one reason why I have taken this cautious approach on overbuilding. It's the spectre of WPPSS hanging over us that makes us cautious going into massive building programs with large capital expenditures."

In his conference speech, Radin said he thought "a prudent interpretation of the facts" pointed to significantly lower electricity demand than industry forecasts projected.

"As a general proposition," he said, "I believe that the uncertainty in future demand for electricity and the high cost of building new capacity argue for concentrating on smaller increments of capacity, cogeneration, conservation, and integration of utility needs...."

Quantitative underpinnings

Radin observed that discussions on how best to meet future electricity demand are often characterized by "solutions" that fail to take into account how much actual capacity will

Continued on page 2

Court: WPPSS participants' contracts invalid

OLYMPIA, WASH.—The Washington State Supreme Court has ruled invalid the existing contracts between public utility participants and the Washington Public Power Supply System for the building of two nuclear plants.

The decision, which stunned some players in the ongoing construction and financing drama, means that although these Washington state municipalities, public utility districts, and co-operatives had entered into contracts with the supply system to construct WNP-4 and WNP-5, they are no longer obligated under the established "take or pay" accord to fund the now-abandoned units (see related story, this issue, page 7).

The state supreme court decision overturns an October 15, 1982 ruling by Judge Joseph Coleman of the King County Superior Court which stated that the participants did have the proper authority to enter into contracts to build these two nuclear plants and therefore were obligated to continue to pay debt service and principal on $2.25 billion in outstanding securities.

The decision to free the participants from liability was based on the court's reading of Washington state law, a WPPSS spokesman said. The court reportedly said that the participants did not have the authorization to enter into "hell-or-high-water contracts" where they could be held liable for construction expenditures even if the plants never produced power.

Continued on page 2

Foreign Power Briefs

- **China** will construct a 900 MW nuclear heat and power plant in Shanghai, says *The Liberation Daily*. The estimated $265 million plant would mainly produce steam, but would be capable of providing 100 MW of electricity. China will design, manufacture and build the plant, said the city newspaper. After government approval is granted, the Shanghai General Petrochemical plant will begin work on the five-year construction schedule.

- **A Saudi Arabian government** program to provide electricity to rural southern areas of the country is getting underway. The Saudi Consolidated Electric Company appointed Bugshan S&W Company, Ltd., a firm jointly owned by Stone & Webster Engineering Corp. and A.S. Bugshan & Bros. of Jeddah, to supervise the project. A central 120 MW power station and over 400 miles of 132-kV transmission lines will be built to provide electricity to approximately 10,000 customers in 430 villages.

- **Ontario Hydro's** Unit 3 at the Bruce nuclear generating station took first place in the 1982 world reactor performance standings in the 500 MW and larger class. Four other Hydro reactors—Bruce 1 and 4 and Pickering 2 and 4—were also ranked in the top ten.

- **South Africa** has begun an emergency effort to build a water supply system for its power plants in the eastern Transvaal region to protect against summer blackouts. The government said engineers will reverse the flow of the Vaal River for about 60 miles. South Africa is in the midst of a severe drought and Electricity Supply Commission officials warn that if the drought continues, power shortages are likely. Coal-fired power plants in the region provide about 66 percent of the country's electricity.

- **French** economists drafting a five-year economic plan have told the government that the country's power requirements have been so drastically overestimated that nuclear plant construction should be halted for two or three years. *Electrical Review* says the economists found the previous forecast, which was made two years ago, gives an exaggerated picture of future energy consumption in France. The economists issued a low-growth forecast of a one percent economic growth to 1985 and two percent beyond. They also released a more optimistic growth forecast of 2.3 percent to 1985 and 3.5 percent for the following years.

- **Afghanistan Prime Minister** Sultan Ali Keshtmand blamed a rash of Kabul power shortages on guerrilla sabotage. During a speech broadcast over Radio Kabul, the prime minister called for damaged lines to be repaired and announced a $55 million project to construct power lines across the Soviet border.

- **A Spanish electric utility** entered into an eight-year, $50 million credit agreement with the Bank of America, Chemical Bank and Crocker National Bank to provide capital for the utility's construction program, said BankAmerica Corporation. Empresa Nacional Hidroelectrica del Ribagorzana S.A. of Barcelona's agreement calls for the issuance of commercial paper in the U.S. and revolving Eurodollar or domestic dollar advances.

- **West Germany's** Lurgi Kohle und Mineraloeltechnik GmbH and Stone & Webster Engineering Corp. signed an agreeement to undertake business development activities for commercial coal-gasification plants in the U.S. and abroad.

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EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (• •). All readers receive EL&P's industry news section.

APPA chief . . . from page 1

be needed.

Walking his listeners through variations on the energy demand/supply scenarios first worked out by economist Alvin Kaufman of the Congressional Research Service, Radin came up with capacity estimates for three demand growth projections (assuming a 20 percent reserve margin):

- For GNP growing at 4 percent per year, and no increase in the annual real price of electricity, the capacity requirement in 1990 could be expected to be 710,000 megawatts (high demand case).
- For GNP growing at 3 percent per year, and a 2 percent annual increase in the real price of electricity, the capacity requirement in 1990 could be expected to be 647,000 MW (moderate demand case).
- For GNP growing at 2 percent per year, and a 5 percent annual increase in the real price of electricity, the capacity requirement in 1990 could be epxected to be 584,000 MW (low demand case).

The North American Electric Reliability Council reportedly has estimated that the industry has planned 724,000 MW of capacity for 1990.

"The 77,000 MW difference between the 724,000 MW NERC says is planned, and the 647,000 MW that seems likely to be required under the moderate demand scenario is hardly academic," Radin said.

"Based on a conservative estimate of $1 million per MW to build a coal plant, at today's prices this 77,000 MW difference amounts to $77 billion."

Reserve margins too high

Radin calculates that when the 572,000 MW that was available in 1981 is subtracted from the NERC figure of 724,000 MW—the total capacity planned by the industry for 1990—the result is 152,000 MW, or the net capacity additions the industry is planning to have available in 1990.

But less than one-half of this amount is needed to meet capacity requirements under the moderate growth scenario of 647,000 MW, he points out.

Further, he calculates that net capacity additions of 152,000 MW implies a reserve margin of 31 percent in 1990, an average reserve margin of 34 percent for the 1982-1989 period, and an average reserve margin of 26 percent planned for the 1990s.

"Why do we have to maintain an average reserve margin of 34 percent for the rest of this decade and an average of 26 percent for the next decade when 20 percent is considered prudent, and even 15 percent by some," Radin asks.

"Why was the industry able to accommodate the prosperous 10-year period prior to the oil embargo with a 20 percent reserve margin but is not able to do so for the remainder of this decade or the next?

"Why was it able to provide for the prosperity of the early and mid-1950s with a reserve margin of 15 percent but is not able to do so for the rest of this decade or the next?

Said Radin, "Changes in the way reserve margins are calculated may be a small part of the explanation, but it would take a whole 'new math' to provide a total rationale."

Other ways than new plants

Even if one were to assume that about 75,000 MW in new capacity additions were needed between 1981 and 1990 (the moderate demand growth case, as opposed to the 152,000 MW NERC currently says are being planned by electric utilities), not all of this new capacity would necessarily have to come from new plants, Radin argues.

"Given the magnitude of future capacity requirements and the high cost of building new power plants, conservation and a variety of energy sources should be looked at first as a means to meet the nation's energy requirements," he maintains.

"Utilities have frequently found that it costs less to finance a loan program for conservation or other similar purposes than to build new energy supplies that would otherwise be needed," Radin adds.

Although he acknowledges that in certain regions of the country, the construction of very large plants may be economically justifiable, he suggests it would be prudent for electric utility managers to look to smaller increments of capacity that could be matched more closely to reasonably foreseeable demand.

Such a strategy would argue for coal-fired or perhaps nuclear units of 500 MW to 600 MW, promising new technologies such as the fuel cell, cogeneration, various renewable energy resources, conservation, and increased inter-regional interconnection and transmission of electric power.

To buttress his arguments, Radin recalls the results of a Massachusetts task force established to investigate options for additional generating capacity in the state. The task force reportedly recommended against building new, large baseload plants to back out of oil use even though a large portion of the state's electricity comes from oil-fired plants.

Instead, the group calculated that the least expensive electricity appeared to come from those utilities able to pursue a range of individual electricity supply actions. The task force recommended more conservation, judicious load management, some rate reform, the encouragement of cogeneration and small power production, and the conversion of oil-burning units to coal.

Concluded Radin, "Pursuing the options suggested by the task force may not have the technological sex appeal, mystique, or grandioseness of building a 1,300 megawatt nuclear or coal-fired plant, but they are likely to be more economical and less risky."

WPPSS . . .

from page 1

At press time the day after the ruling, the spokesman was unsure how the supply system would respond.

Few observers thought the Washington Supreme Court decision constituted the final word on the matter. "Round 2 is coming up," the WPPSS spokesman said.

Chemical Bank, bond trustee for nuclear units 4 & 5 immediately released a statement that said it would petition the state high court to reconsider its decision, adding that it would amend its earlier complaint in trial court "to assert fraud." It named numerous objects of its redirected allegations, including the supply system and the legal counsel that had rendered opinions on the bonds before they were issued.

Preliminary assessments of the impact of the ruling suggested that supply system default was now a virtual certainty, while the possibility of actual bankruptcy was significantly enhanced.

Sulfur-trioxide flue-gas conditioners allow reduced precipitator size

It's possible to collect high-resistivity fly ash from boilers burning low-sulfur 'problem' coal types in precipitators much smaller than the 600-800 SCA units commonly being specified, according to Wahlco, Inc., a supplier of sulfur-trioxide flue-gas conditioning equipment. Conditioned precipitators could be a third cheaper than the large ones, the firm claims.

What makes that claim hard to dismiss is the success at Wisconsin Electric Power Co.'s Pleasant Prairie station over the past three years. A 468-SCA cold-side precipitator supplemented by a Wahlco sulfur burner has been achieving reliable operation, collection efficiencies of 99.95 percent, and opacity levels of 2 to 5 percent. It's performed "better than a baghouse" in some tests, WEPCO engineer John Neldner told the American Power Conference in a report on the installation.

Pleasant Prairie is the first to use sulfur trioxide conditioning with a new precipitator, but Wahlco hopes it's not the last. The company has an impressive record with its sulfur burners over the past few decades with about 150 installations, but they've almost all been retrofits—usually at stations switching from a high-sulfur coal that produced a fly ash that could be easily collected in the plant's small precipitator to a low-sulfur coal that produced a troublesome, high-resistivity fly ash.

The development of automatic, unattended load-following sulfur-burning systems in recent years makes it possible to design them into the original fly ash collection system, says Wahlco vice president Robert Reveley. The payoff, he says, is a precipitator 33 to 54 percent smaller than would otherwise be required.

The firm's director of environmental activites E. L. Coe expanded on that idea in a paper presented at the EPA particulate control symposium in Houston last October. He presented an economic comparison (see Table 5) that showed a huge cost advantage for incorporating flue gas conditioning in the initial system design.

Coe postulated a 600-MW plant with 2.6 million acfm of flue gas from burning a low-sulfur western coal type and a 99.9 percent particulate collection requirement. A key criterion in the analysis is the assumed particulate migration velocity in the precipitator. Coe assumed 4.0 cm/s for the unconditioned precipitator and 8.0 cm/s for the conditioned case—assumptions he says that favor the unconditioned case.

The conditioned precipitator needs only 440 SCA, or a collecting area of 1.144 million square ft, to do the job, said Coe. Precipitator cost would be $25.2 million and conditioner cost would be $2.5 million. The unconditioned precipitator is twice as big, at a cost of $42 million. Coe said the net output would be 1.4 MW lower with the larger, unconditioned precipitator, so the resulting capital cost favors the small, conditioned system by about a third.

Coe's analysis also shows a huge advantage in operating costs with the power consumption savings of the half-size, conditioned unit larger than the added sulfur and O&M costs compared to the unconditioned type.

As mentioned earlier, Wahlco's confidence is bolstered by the success at Pleasant Prairie. The story of how sulfur trioxide conditioning came to be included in the original plant design has been told before (see *EL&P*, Sept., 1981, page 26.) The story now is how well the small-precipitator/flue-gas-conditioner combination has performed for the past three years.

Information on the Pleasant Prairie system is shown in the tables. The plant burns Powder River basin coal and was originally intended to have a relatively small (305 SCA) hot-side precipitators. While the plant was still in the design phase, WEPCO decided to drop the small, hot-side plan. ("We heard some horror stories early," WEPCO engineering vice president Huberto Platz told the American Power Conference meeting, adding, "We were lucky. It's time A-E's and operating companies exchange information early in the game so people don't get into trouble. Instead of only talking about good results at conferences like this we should be more forthright about our failures.")

Since the Pleasant Prairie precipitator was already being fabricated it proved most economical to move the unit to the cold side and enhance collection efficiency with sulfur trioxide gas conditioning.

The collection system for the 617-MW unit 1 has four precipitators with two chambers each. The total effective collecting surface area is 1.2 mil-

Continued on page 26

TABLE 1.
PLEASANT PRAIRIE PRECIPITATOR SPECIFICATIONS

Design gas volume	2,600,000 ACFM @ 290°F
Design collection efficiency	99.72
Number of precipitators	4
Number of fields in series	8 @ 4½ ft
Collecting plate height	36 ft
Treatment length	36 ft
Total collecting plate area	1,223,424 sq ft
SCA	468 sq ft/1000 ACFM
Drift velocity, w	6.38 cm/sec

TABLE 2.
COAL AND ASH ANALYSIS

	Average	Range
Moisture, %	29.2	20.9-32.1
Ash	6.12	5.31-7.26
Sulfur	0.47	0.19-0.58
HHV, Btu/lb	8213	8052-8376

ASH

SiO_2, %	30.6	MgO	8.1
Al_2O_3	12.6	K_2O	0.24
Fe_2O_3	7.2	TiO_2	1.1
CaO	22.2	Na_2O	0.90

TABLE 3.
EFFECT OF SO_3 INJECTION ON RESISTIVITY

SO_3 Injection ppmv	Gas temperature °F	In-situ resistivity ohm-cm
0	260	3×10^{10}
	280	1×10^{11}
5	300	5×10^{9}
7	300	1×10^{6}
15	300	7×10^{7}

TABLE 4.
PLEASANT PRAIRIE PRECIPITATOR TESTS WITH SO_3 FLUE GAS CONDITIONING

Date 1981	MW	SCA ft^2/1000 ACFM	Efficiency %	w cm/sec	gr/DSCF	Outlet lb/10^6 Btu
6/9	587	506	99.97	8.15	0.0008	0.0016
6/10	580	505	99.945	7.55	0.0017	0.0034
6/11	583	502	99.97	8.22	0.0012	0.0024
6/16*	572	354	99.93	10.42	0.0021	0.0042
	572	348	99.89	9.94	0.0034	0.0068

*Tests of 6/16 conducted with two fields (1/4) of precipitator de-energized.

Control panel for flue-gas conditioning system at Lansing Board of Water & Light.

TABLE 5.
ECONOMIC EFFECT OF CONDITIONING

Investment cost	Unconditioned $1,000's		Conditioned $1,000's
Installed cost—precipitator	42,000		25,200
gas conditioner	–		2,500
Capacity charge	Base		(1,395)
TOTAL	42,000		26,305
Difference		15,695	
Annual cost			
Fixed charges @ 20%	Base		(3,139)
Energy	Base		(304)
Sulfur	–		134
O & M	Base		93
TOTAL	Base		(3,126)

Source: "Economical Fly Ash Collection by Flue Gas Conditioning," E. L. Coe, Wahlco, Inc.

TABLE 6.
WESTERN COAL FLUE GAS CONDITIONING INSTALLATIONS

Utility	Station	No. boilers	Total MW	Total gas volume (1000's ACFM)	Coal
Central Illinois Light Co.	Wallace	4	254	1040	Colorado and Utah
	Edwards	3	725	2646	
Colorado Springs Dept. Public Utilities	Martin Drake	1	44	211	Colorado
Commonwealth Edison Co.	State Line	11	963	4950	Western
	Joliet	7	1787	7700	Carch Mineral Decker, Black Butte
	Waukegan	4	606	3050	
	Crawford	2	597	1800	
	Fisk	1	374	1300	
	Will County	1	598	1750	
	Powerton	2	893	1700	
Iowa Public Service Co.	Neal 2	1	350	1086	Western
Lansing Board of Water & Light	Erickson	1	160	570	Western
Northern Indiana Public Service Co.	Mitchell	4	552	2140	Westmoreland
Public Service Co. Colorado	Arapahoe	2	88	590	Energy, Powder River
Utah Power & Light Co.	Naughton 3	1	326	1650	Kemmerer
Wisconsin Electric Power Co.	Pleasant Prairie	1	580	2600	Rawhide

Source: Wahlco

Railcars . . . from page 20

pany, says, "There's some question as to whether aluminum center sills can withstand unit train service. That's why we stayed with steel there." The Ortner design uses aluminum for the "coal-carrying envelope" and the car end structure to take advantage of the material's corrosion resistance and low weight. Steel is used in areas of high wear and fatigue such as center sills, draft lugs, cross ridge webs and gussets, body bolster webs, cover plates, and rear gussets.

Ortner said he recalls no previous use of all-aluminum coal-carrying cars but there have been trials with composite designs for gondola cars. He said the Southern Railroad has used composite gondolas (see photo) for several years. He said his firm supplied some for Detroit Edison that have aluminum sides and steel underframes. However, Ortner added that the Santee Cooper order is the first he recalls for composite hopper cars capable of bottom unloading.

He said that one reason for the improved outlook for aluminum is a change in railroad attitude. "Some railroads are finally realizing there are benefits to them," he explained. "If railroads continue to offer an incentive, aluminum has a good future in rail cars." Rising fuel prices and deregulation have played a role.

The other side of the economics equation is in the hands of the materials suppliers, explained Ortner. He said that the relative prices of aluminum and steel favor aluminum right now because they allow carmakers to build aluminum cars at a price premium of only 25 to 30 percent. In the past the premium has been higher and, in fact, some of the utilities that pioneered the use of aluminum in rail cars stopped because its price premium got too high. Ortner noted that if the aluminum suppliers maintain the price gap where it is now, then aluminum has a good future.

Alcoa, a Pittsburgh-based aluminum producer that's supplying material for the Ortner order, is actively trying to develop the coal-carrying railcar market by offering to do individualized economic analyses of the benefits of aluminum. The company says it recently analyzed a western coal haul in which the payload carried by 904 steel cars in 285 trips could have been carried by the same number of aluminum cars in 271 trips.

According to Alcoa's railroad marketing manager W.B. Groves, "Over a 20-year operation period that's 280 trips locomotives and train crews won't have to take, 280 hauls that won't have to be loaded or unloaded, and resultant reductions in fuel, labor and track maintenance costs. It also means less wear on the cars, saving running repair costs."

The 904 aluminum cars in the Alcoa analysis each weigh 41,000 lb, 11,000 lb less than lightweight steel cars. Resulting operating and repair savings total more than $2 million a year. "Though an aluminum unit train car will initially cost more to buy than a conventional steel coal car, the incremental investment can produce a real internal rate of return up to 40 percent and more, without financing," according to Alcoa planning analyst Joseph Tribendis.

"Leasing aluminum cars from a third party also presents distinct advantages," Tribendis added. "Our study shows that savings will more than cover incremental lease costs for any combination of weightsavings of five tons or more and annual use of the car for 60,000 miles or more. For example, assume leasing an aluminum car, which offers a five-ton weightsaving, costs $1000 more per year than leasing an ordinary steel car. If the car travels 60,000 miles per year, the annual operating and maintenance savings would be $1430. The lessee would save $430 per year. That's a 43 percent saving over the incremental lease cost. An aluminum car weighing seven tons less than a steel car and traveling 100,000 miles per year would offer the lessee a 276 percent saving over the incremental lease cost."

Alcoa adds that aluminum's price disadvantage becomes an advantage when the car is scrapped. The company says that the scrap value of an average aluminum car today would be $4798, compared to a steel car's $1170.

Alcoa says the outlook is for the aluminum-steel price gap to remain the same or to change in aluminum's favor in the future. That's because the aluminum industry has retired high-cost capacity during the past recession and does not plan to bring it back on line due to modest demand-growth expectations. "We don't see any soaring in aluminum prices," says a spokesperson. Alcoa feels there will be more intense upward price pressure on steel suppliers to restore industry profitability.

Wahlco . . . from page 23

lion sq ft. On the hot side, with 4 million ACFM at 800F, the SCA would have been 305. On the cold side of the air preheater at 280F, the flue gas flow is 2.6 million ACFM, so the effective precipitor SCA was 468. That was still quite small as cold side precipitators go, especially for a coal producing a high-resistivity fly ash.

Precipitator hardware cost in 1979 dollars was $10.50 a kW. Total, in-place unit 1 precipitator cost was $41/kW. The gas conditioning system added $1.60/kW to the hardware costs and $3.25/kW to the overall system cost.

Molten sulfur is delivered to the southern Wisconsin plant from a source in Illinois, 80 miles away. It's stored at 275F. The sulfur is pumped to the burner/converter which produces sulfur trioxide. The equipment is housed in two 20 X 40 ft enclosures next to the precipitators (for both units 1 and 2). The sulfur trioxide is injected into the precipitator inlet ductwork. A concentration of 8.5 ppm SO_3 is normally maintained.

Results of 1981 acceptance tests are shown in table 4, taken from Coe's paper. WEPCO's Neldner told the APC that performance tests in 1981 conducted by EPRI showed that precipitator efficiency was 99.95 percent and particulate emission rate at the outlet was 0.002 lb//MMBtu. Other tests, said Neldner, showed efficiencies of 99.91 percent and 99.96 percent. He added that the precipitator performed better than a baghouse, even on submicron particle sizes.

An interesting question was posed to Neldner at the APC presentation. A man who said he was from Iowa Public Service Co. said that the utility's Neal station burns a problem coal and uses sodium conditioning to enhance precipitator efficiency. He said that over time a hard coating builds up inside the precipitator requiring sandblasting to get rid of it.

Neldner said there was no comparable buildup at Pleasant Prairie. The "light dusting" that does occur doesn't require any periodic washing. He added that there have been no erosion problems either with the injection nozzles. Noting reports that the catalytic converters on some conditioning systems have deteriorated after about five years, Neldner said he hasn't seen that yet at Pleasant Prairie but is aware of the possibility. Concluded Neldner, "After nearly three years of operation the performance of the Pleasant Prairie Unit 1 precipitator and gas conditioning system remains excellent."

Western coal challenge

A major opportunity for precipitator size reduction is in applications where "problem" coals are being burned—coals, that is, that produce fly ash that is difficult to collect. Wahlco's Coe says, "We tend to view Western, low-sulfur coals as members of a worldwide population which produce fly ashes that are difficult to collect in electrostatic precipitators because of their high resistivity."

As mentioned earlier most of Wahlco's sulfur-burners have been retrofitted to existing power plants. A list of those that switched to Western coals is shown in Table 6.

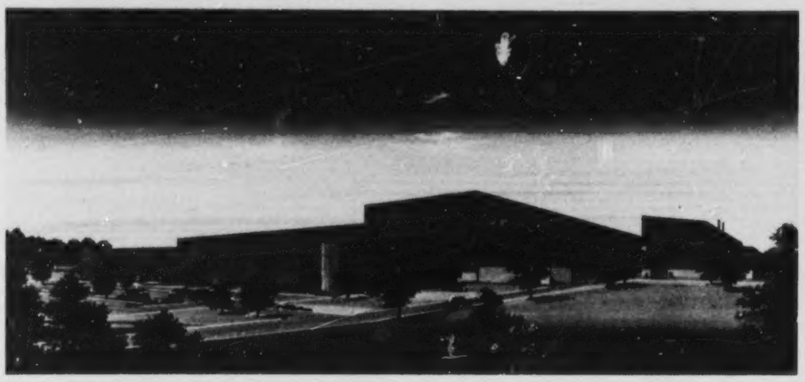
An example is the Lansing, MI Board of Water and Light's 160-MW Erickson plant. From 1973 to 1980 the plant burned coal with 3 to 3.5 percent sulfur and unconditioned fly ash was collected in a 99-percent efficient precipitator with an SCA of 185. The emission limit was 0.17 lb per 1000 lb.

Conditioning cheaper

The state required the plant to switch to coal with less than one percent sulfur in 1980 and the utility recognized that the reduced sulfur content would result in a harder-to-collect, higher-resistivity fly ash. In order to comply with the particulate emission limit the utility considered enlarging the precipitator; replacing the precipitator with either a new hot-side unit, a new cold-side unit, or a new baghouse; or use of the existing precipitator with flue-gas conditioning. Wahlco says the utility found that the cost differential was ten to one in favor of conditioning.

Testing has shown particulate emissions well within the limits for the past three years on East Kentucky low-sulfur coal. The utility says the conditioner requires little maintenance, staying on line through the power plant's 18-month operating periods between scheduled outages.

S-A and UPC announce Florida facility



Manatee, FL, plant of Utility Power Corporation and Siemens-Allis, shown in architect's rendering, is scheduled for completion in 1985.

BRADENTON, FL—Siemens-Allis, based in Atlanta, and Utility Power Corporation, headquartered here, have announced plans to construct a half-million square foot office, manufacturing and service facility in Manatee County. The office portion of the $50-million-plus facility is scheduled to be completed in early 1984, with the factory portion to be completed in 1985.

Utility Power Corp., formed in 1978 by Siemen's Kraftwerk Union and Allis Chalmers, will use its portion of the plant for the manufacture and assembly of components for steam turbine-generator units rated 300-Mw and above. The plant will serve as the company's U.S. service center as well. UPC's service, engineering, manufacturing and marketing personnel already located in Bradenton will be moved into the new facility when it's ready.

The new facility also will serve as the home of Siemens-Allis' large rotating apparatus division, which makes hydro generators and large motors. This operation, currently involving some 500 people in West Allis, WI, will be moved to the Manatee plant by late 1985.

Duke Power gets cogeneration contract

CHARLOTTE, NC—Duke Power announced that its in-house architect-engineering group has won a contract for a conceptual design of a coal-fired, 25-MW cogeneration plant.

The contract was awarded by a firm called Cogentrix of North Carolina, Inc. which plans to build cogeneration facilities for the textile and other industries in North and South Carolina based on the conceptual design.

"Our objective," said Don Blackmon, manager of business development for Duke Power, "is to provide a concept for a station which is visually acceptable, environmentally compatible, and will meet the requirements of PURPA." Duke said the design would be completed by late July or early August.

"Our department has done a number of engineering projects for other companies, but this is a unique undertaking," said Blackmon.

CE to sell Lurgi circulating fluid bed

STAMFORD, CN—Combustion Engineering announced that it signed an agreement with Lurgi Corp. that "combines Lurgi's process technology and circulating fluidized bed combustion experience with C-E's coal-burning steam generator technology and equipment and bubbling fluidized bed experience."

CE says the two firms will jointly provide both types of fluidized beds.

Utility PCB-capacitor replacement programs lag; compliance deadline could be a problem

BLOOMINGTON, IN—Unless electric utilities begin to accelerate and expedite PCB capacitor changeout programs, they could find themselves in difficulties as the October 1, 1988 deadline for complete elimination of PCB units approaches. This is the conclusion of a study recently completed by Westinghouse Electric Corp.

"If enough procrastinate, many of the units that could be changed out in the early years will slip into the later period," says Kenneth O Tison, Westinghouse's Capacitor Product Manager. "In fact, order rates so far in 1983 indicate this already is beginning to happen. Fewer units are being changed out than had been anticipated.

"It's going to take a significant increase in changeout activity in 1984 to avoid capacity problems in later years."

Pace slowed

The Westinghouse executive said that utilities have slowed the pace of changeout programs because of a variety of reasons. These include their own financial difficulties, lack of manpower, a belief that regulations might be relaxed or changed to allow continued use of existing PCB capacitors or landfill disposal, and concern that approved PCB-capacitor destruction facilities are inadequate to handle the load.

Not only can such procrastination lead to compliance problems down the line, he suggested, but those utilities that hold off changeouts will miss out on the benefits that can accrue from upgrading, the higher power factors of new capacitors and the resultant savings from reduced losses.

Adequate manufacturing capacity

Published NEMA figures show that the capacitor manufacturing industry is running at less than 60 percent of capacity, a level that may surprise some utility executives because of apparent capacity problems that arose when the initial surge of changeout orders hit the market in 1980 and 1981.

Potential capacitor manufacturing capacity, according to several studies, is about 300,000 cans [units] per year, or about 50 gigaVARS of capacitors, based on an average size of 165 kVAR. Westinghouse says its surveys indicate that essentially all this capacity is readily available today because manufacturers geared up substantially to handle increased changeout volume over the last two years. Facilities have been improved and streamlined and the productivity of such functions as winding, assembly, impregnation and assembly has been stepped up.

Market trends

Tison says that the PCB replacement market has been a rapidly growing segment of the overall capacitor market, increasing from nothing in 1979 to 54,000 cans by 1981. But then the growth halted. About 54,000 cans also were shipped in 1982. A gain to 60,000 cans appears possible this year. In the same period, shipments to meet normal new capacitor needs increased by 20 percent to 1981, held steady in 1982, but appear to be off substantially this year.

Overall, the total of HV capacitor cans shipped peaked in 1981 and 1982 and appears to be off, to a rate of 170,000 cans for 1983. See the table below. Clearly, as Tison points out, "the industry's current 300,000-can per year capacity is seen to be more than adequate for today's needs."

HIGH-VOLTAGE CAPACITOR CANS SHIPPED

	1979	1980	1981	1982	1983
Normal Capacitor Needs	105,000	104,000	126,000	126,000	110,000
For PCB Replacement	0	18,000	54,000	54,000	60,000
Total	105,000	122,000	180,000	180,000	170,000

It also appears that today's comfortable capacitor manufacturing capacity margins will carry some years into the future, although, as Tison says, accurate forecasting of normal capacitor needs always has been difficult. Such forecasts often are based on the prior year's peak load growth, kVAR of installed capacitors in use and other economic indicators of electrical usage. Negative peak load growth in 1982 has led to a reduced capacitor market so far this year, according to NEMA figures. And although the Federal Energy Regulatory Commission, EEI and others are forecasting resumption of load growth in the future, nobody is expecting anything extraordinary.

Thus, it would appear that the normal capacitor market will be tempered during the period through October 1, 1988, when all PCB capacitor changeout programs must be completed. Tison suggests an average market of 130,000 cans per year, based on historical data.

The Edison Electric Institute estimated that the total number of PCB capacitors to be replaced totalled about 1.4-million units. Assuming changeout on a one-for-two basis (as a result of going to higher average kVAR ratings) would mean a total PCB capacitor replacement market of about 700,000 cans. Subtracting the 186,000 cans that Westinghouse estimates will have been shipped by the end of this year leaves a market of about 514,000 cans or a bit more than 100,000 cans per year, Tison says.

This scenario doesn't allow for 1988 being less than a full year (the deadline for changeout being October 1 in that year), he warned.

The table below shows what the 1984-1988 picture could look like.

HIGH-VOLTAGE CAPACITOR CAN ESTIMATES

	1984	1985	1986	1987	1988
Normal Capacitor Needs	130,000	130,000	130,000	130,000	130,000
For PCB Replacement	100,000	100,000	100,000	100,000	100,000
Total	230,000	230,000	230,000	230,000	230,000

As Tison points out, the scenario of demand shown above falls well within the industry's manufacturing capacity of about 300,000 cans per year. It assumes, he says, no significant increase in average can size, even though larger can sizes in the ranges of 300- to 400-kVAR have recently become available. This, he suggests is because large numbers of 50- and 100-kVAR cans still are being ordered for changeouts. In fact, one company that had dropped 50-kVAR units from its line has begun to make them again, apparently to serve the PCB replacement market.

Utilities slow changeout pace

The problem Tison foresees is a backing up of demand and then a rush by utilities to catch up and comply with the mandated deadline.

For example, should utilities move toward the changeout deadline slowly, perhaps increasing each year's changeouts by 10 percent over the previous year, by the end of 1987 they would have changed out only 306,300 cans, leaving 208,000 non-PCB cans to be changed out in the first nine months of 1988 to comply with the deadline. This requirement, coupled with normal capacitor demand would exceed the manufacturing capacity of the industry.

Should the changeout rate remain relatively constant at the 1982 level, or even at the projected 1983 rate, for several years, the problem posed for the industry would be even more acute in the later years preceeding the deadline.

Disposal concerns

Utilities are concerned about the availability of PCB-equipment disposal areas, Tison explained. Although disposal capacity has greatly increased in 1982 and so far in 1983 as existing facilities have expanded and new facilities have come on-line, disposal organizations have trouble handling current loads. Larger facilities are running with three- to four-month backlogs at present changeout rates. This, he said, means that capacitors delivered today for destruction won't be disposed of for four months. It is Tison's belief that "this situation will probably get worse as changeout activity picks up.

"Those who delay their programs could run into very high prices and long waits to get their capacitors destroyed. Thus, disposal capacity considerations, along with manufacturing capacity concerns, dictate that utilities take early and orderly action on changeout programs to help levelize the load on industry facilities as well as avoid the expense and delays of being caught in any future crunch that may occur," Tison declared.

Upgrading opportunities

According to the Westinghouse executive, many of the capacitors that are going to be changed out have been in service for many years. Both bank size and location probably are not optimal because the system has grown gradually over the years. Several utilities, he said, are viewing their PCB changeout programs as ideal opportunities to study their systems and optimize capacitor bank sizes and locations on distribution feeders.

"Until about 10 years ago, a power factor of 0.91 or 0.92 was considered to be an economical target to shoot for. But with today's fuel and energy costs, target power factors in the range of 0.97 to 0.99 are both economical and realistically attainable," he explained. "For utilities that upgrade their power factors and properly locate their distribution capacitors, the savings from reduced losses can, in many cases, be more attractive than those being realized from the purchase of low-loss transformers."

Another benefit

Another upgrading benefit is inherent in newer capacitors that incorporate all-film designs having losses as low as 0.1 watts per kVAR, compared with losses in PCB capacitors of about two watts per kVAR for all-paper or 0.6 watts per kVAR for paper-film designs.

Oglethorpe Co-op adopts standard substation designs

ATLANTA—Oglethorpe Power Corp., the big Georgia generation/transmission co-op, has announced that it has begun developing a series of standard designs for new substations. The co-op hopes the standard designs will save construction time and money.

The first substation to be built from a standard design will be constructed this year.

Standard designs already have been developed for some types of 115-kV substations, with standardized designs for the balance of 115-kV subs and for 46- and 230-kV substations to follow over the next two years.

Under the new system, identical parts in substations of the same voltage will be interchangeable, reducing spare parts inventory to a minimum.

In addition to the advantages resulting from parts interchangeability, the new practice will reduce the co-op's substation design and drafting time, improve reliability and reduce the time and expense of field modification.

The standard substation types already designed are two versions of the 115-kV loop-through, fused substation. A standard 115-kV automatic fault-interrupting motor-operated substation is currently undergoing field tests, as well.

Sangamo to sponsor fall seminar on fault analysis

ATLANTA—The Energy Management Division of Sangamo will sponsor its first annual Fault and Disturbance Analysis Seminar here in September. The two-day seminar will allow presentations of various analysis philosophies, provide insights into the analysis of fault recording and stimulate discussion of applications.

Information can be obtained from: Fault Analysis Seminar, Sangamo, Dept. J686, Atlanta, GA 30362.

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Power shortages by 1993 if no new financing incentives, DOE electricity report concludes

The electric utility industry is living on borrowed time.

That's the basic conclusion of the long-awaited Electric Policy Project report just released by the Department of Energy.

The current institutional, regulatory, and financial situation in the electric utility industry is imposing powerful disincentives on power companies to invest in new generating capacity, DOE calculates, and these disincentives will lead to a measurable lessening in electric service reliability by 1990 and inadequate generation a few years later.

Unfortunately for those who had been expecting recommendations for changes in public policy, the report is confined to a description of what the department believes are the current problems facing the industry.

Issued with the intention of providing "a springboard for discussion and debate," the report is expected to be followed by another document that will explore appropriate actions the federal government can take to remedy the concerns.

Criticism of the report had surfaced months before it was issued. Work had been well under way when Donald Hodel was appointed the new Secretary of DOE, and it was he who found policy change recommendations contained in the first draft less than acceptable. He therefore split the enterprise into descriptive and remedial segments, hoping thereby not only to solicit broader industry and public debate on the issues, but to have the final policy change recommendations more forcefully reflect his own views.

Release of the descriptive report has not stemmed the flow of criticism. One of the more vehement attacks on DOE's version of problems presently facing the electric utility industry has come from Rep. Richard Ottinger (D.NY), chairman of the House Subcommittee on Energy Conservation and Power and perennial critic of nearly all the electric utility industry perceives is in its own interest.

Shortly after the DOE report was issued, Ottinger released a statement charging that "The Department of Energy raises the false spectre of a

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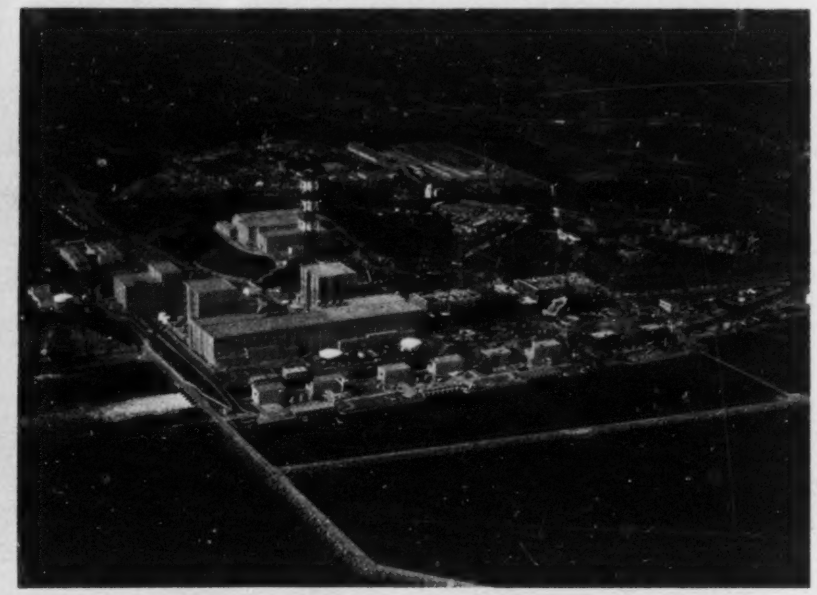
BWR sets record for continuous run



Tokyo Electric Power Company's 1100-MW Fukushima Daini Unit 1 boiling water reactor set a record for light water reactor operations on its maiden run. The Toshiba-built unit began its run on April 4, 1982, and ran for 400 straight days. The previous record was 392 days. The unit, based on G.E.'s BWR design, also operated at 98.1 percent capacity factor during the period.

Electricity growth lags during economic recovery

But some hints of improvement are seen in 1983 data

Dan Utroska
Associate Editor

BARRINGTON, IL—Despite widespread reports that the economy is recovering swiftly and strongly, gross national product advanced sluggishly during the first half of 1983. And while electricity demand did not even match GNP's funeral pace, it did show some faint signs of turning around.

According to figures compiled by the Commerce Department's Bureau of Economic Analysis (BEA), gross national product, as measured by the change in constant dollar figures, increased 1.6 percent during the first half of 1983 as compared to the same period last year.

Kilowatt-hour growth, however, declined about 1.8 percent during the same comparative period, according to *Electric Output* published by the Edison Electric Institute.

The Department of Energy also compiles electricity generation figures, which differ from electricity output figures by the exclusion from

Continued on page 3

Flurry of reports call for action to fight acid rain

Don Minner
Assistant Editor

A shifting tide of opinion now seems to favor the use of stricter emission control limitations to fight the battle against acid rain.

A number of scientists, legislators, top Reagan administration people and even an electric utility are calling for action to reduce emissions from plants across the country after finding that there is a direct link between plant emissions and acid rain.

For the first time, a panel of advisors to the White House said immediate action should be taken to reduce sulfur dioxide emissions. This recommendation contrasts with the administration's position that more time is needed to study the problem before taking steps to clamp down on the amount of emissions being released from plants.

The team of nine scientists, headed by William Nierenberg, presented its findings to Environmental Protection Agency Administrator William D. Ruckleshaus and to President Reagan's Office of Science and Technology.

Damage may be irreversible

"If we take the conservative point of view that we must wait until the scientific knowledge is definitive, the accumulated deposition and damaged environment may reach the point of irreversibility," said the panel.

No specific pollutant reductions were recommended by the group, but the scientists urged that "economically efficient" steps first be taken to reduce emissions.

Nierenberg's team admitted that a reduction below present sulfur dioxide emission levels would possibly allow recently acidified areas to return to their original biological conditions.

The group, which was formed in 1982 to review U.S.-Canadian scientific studies and to provide an independent assessment of the acid rain problem, said that sulfur dioxide and nitrous oxide emissions in eastern North America are at least ten times larger from human activities than from natural processes.

But, cautioned the panel, "The overall scientific understanding of the various aspects of acidic precipitation is quite incomplete at the present time, and will continue to have major uncertainities well into the fu-

Continued on page 7

Safequards report issued by NRC

Although there are at present no clear and present nuclear power plant safety problems resulting from the implementation of security requirements, the potential does exist at some plants for compromised safety due to safeguards measures, a special committee of the Nuclear Regulatory Commission has concluded.

"The degree of internal compartmentalization for security purposes (vital areas) can adversely affect operational safety," the *Report of the Committee to Review Safeguards Requirements at Power Reactors* (NUREG-0992) states.

The committee was formed in October 1982 at the direction of the NRC chairman to review the potential impact of safeguards and security measures on nuclear power plant safety.

Investigations revealed that operational safety was especially vulnerable during abnormal or emergency plant situations, if operational personnel were not provided with keys or other methods for gaining prompt access to all plant areas should normal card key access systems fail.

The NRC safeguards/safety committee recommended that nu-

Continued on page 6

Foreign Power Briefs

- **India** received an offer from U.S. Secretary of State George Schultz to provide India with new parts for the Tarapur nuclear plant, if the parts can't be bought from other countries. The State Dept. said India may be able to acquire parts from France, Taiwan or Japan. India says it needs the parts to replace older ones that have made the plant unsafe to operate. Since India does not accept international treaties designed to prevent the use of nuclear fuel for weapons, Congress might veto any sale of parts to India.

- **Hydro-Quebec** will build the world's largest vertical-axis wind turbine at Cap Chat, on the Gaspe Peninsula. The $35 million project will have a 4 MW capacity and be approximately 30 stories high. Hydro's Institute of Research and the National Research Council of Canada will share the cost. The utility will build the prototype turbine.

- **Leiden, Holland** is expected to save $2.4 million a year in operating costs after a new cogeneration system is installed. Two 25-MW Rolls Royce industrial gas turbine sets have been selected to power the cogeneration plant for the Dutch city. The plant, with waste heat recovery boilers and a steam turbine, will provide 84 MW.

- **South Africa and Lesotho** are discussing the Lesotho-Highlands Scheme, a $1.8 billion project for a water supply system to make Lesotho self-sufficient electrically and to provide water for South Africa industry. The project would divert water from the upper Orange River in Lesotho and include five dams and 75 miles of tunnels. If both countries approve construction, the project would be completed in 2004.

- **A Canadian Electrical Association (CEA)** safety study of 14 major utilities in Canada reports that linemen were the workers most likely to have had an accident in 1982. The study says the most frequent cause of injury was to be struck by falling objects. The largest number of accidents were to hands and fingers. The CEA says that over the past four years there has been a dramatic decline in both frequency and severity rates of accidents.

- **Germany's** Federal Ministry for Internal Affairs will draw up new guidelines for nuclear power plant design. The new rules would require the plants to be protected against 36 different kinds of incidents ranging from leaks to explosions, earthquakes and fires. The rules would be an addition to present regulations that require facilities to be air-crash proof.

- **The Japanese government** gave approval for a new PWR nuclear plant. The Electric Power Resources Development Co-ordination Council gave the go-ahead for the construction by Shikoku Electric Power of the 890 MWe Ikata 3. Current plans call for construction to begin in August 1985, with completion by March 1990.

- **France's Atomic Energy Authority (CEA)** is calling for all European countries to join together and develop technology and sales of fast breeder reactors. *Electrical Review* magazine reports that CEA General Manager Michel Pecqueur has called for a European coalition to bring together resources and means to push for a breakthrough of the fast breeder into commercial markets. He *suggested the group be based on an extension of the technical* and industrial agreements which already link France, Italy, West Germany and Belgium as partners in construction of France's Super Phenix fast breeder.

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Clinch River is uneconomical, the Rand corporation says

The current strategy for developing the breeder reactor, including construction of the Clinch River breeder project (CRBR), cannot be justified on economic grounds, the Rand Corporation has concluded.

The well-known research and public policy organization also believes that development of the liquid metal fast breeder reactor (LMFBR) based on energy security arguments is "extremely problematic."

In a letter to Senator John Heinz (R.PA) Rand President Donald B. Rice rejected the notion that Congress should focus on the degree of technological sophistication embodied in breeder design when it debates whether or not to continue funding for Clinch River.

"Instead," Rice wrote to Heinz, "the fundamental issue is whether the present CRBR project and the LMFBR program are essential to and consistent with national energy requirements."

It is Rice's view they are not.

Rice discussed five parameters that Rand analysts believe are critical to any decision to build Clinch River. Electricity demand projections, the number of light water reactors (LWR's) in operation or planned, uranium prices, fuel reprocessing, and alternative fuel breeding techniques were all seen to mitigate against going forward with continued construction of Clinch River.

With respect to electriciy demand, Rice said that the estimated high growth rates over the next two decades—upon which the CRBR project was predicated—are not seen to be overstated.

Second, with no new reactors ordered since 1974, coupled with the scores of reactor projects that have been cancelled in recent years (some already under construction), the LWR population is certainly not growing as it has been expected to grow when the Clinch River project began.

"Without a large and expanding population of light water reactors, a breeder to produce fuel for LWR's loses its justification," Rice declared.

Regarding nuclear fuel, Rice noted that expectations of the early 1970's that future uranium supplies would be uneconomic have not been realized. "If sufficient uranium to support the nuclear plant inventory of the early 21st century can be obtained more cheaply than the plutonium generated by CRBR-type plants, there is no economic justification for continuing the present line of LMFBR development," Rice said.

The Rand Corporation executive also addressed the lack of nuclear fuel reprocessing in the U.S. He noted that reprocessing must be developed concurrently with any breeder program, and "developing that essential reprocessing capability may be as difficult as developing the breeder reactor itself."

Finally, Rice concluded that even if all of these elements could be shown to justify continued breeder progress, it still has to be demonstrated that the LMFBR is the most promising of the breeder options. One alternative, suggested by Rand and other institutions, is the accelerator breeder that would result in plutonium from a uranium fuel cycle or fissile uranium from a thorium-based fuel cycle.

In the longer term, the hybrid fusion system appeared to Rice to be even more promising. Like the accelerator breeder, this technique could breed reactor fuel although it would not be coupled to a power-producing reactor.

Basing his conclusions on these arguments, Rice said, "In view of the lessened apparent urgency of the CRBR project and its clearly diminished role in the national energy program, I would...urge that the nation explore its technical options and possibilities, and that we eschew committing ourselves to the CRBR and the strategy that it embodies."

"I would recommend," he added, "that the Department of Energy be asked to develop an alternative, lower cost R&D program that emphasizes step-by-step, sequential development of several technical approaches, pointing toward a much later deployment time than that currently envisioned for the LMFBR."

Financing plan for CRBR is created

WASHINGTON, D.C.—A new financing plan for construction of the Clinch River Breeder Reactor has been completed and presented to the secretary of the Department of Energy.

The plan, which is expected to provide a 40 percent reduction in on-budget federal funding for the project, is said to be supported by a wide spectrum of organizations, including investor-owned, municipal, and rural electric cooperative utilities; labor unions; nuclear industry manufacturers, and architect-engineers.

It is anticipated that the plan will raise as much as $1 billion.

The American Energy Development Corporation has been formed as a private financing vehicle that will seek, with the support of appropriate legislation, to secure through borrowing up to two-thirds of the private funds that will be expended on the enterprise. The borrowings will be secured by revenues from future power sales.

The other third is to be raised through new equity participations plus funds already committed by the utility industry and others.

All new investments would be backed by DOE contracts, the plan foresees.

According to James O'Connor, chairman of Commonwealth Edison Co., and chairman of the Breeder Reactor Corporation, the proposed plan meets the requirements set forward recently by Congress regarding funding for Clinch River.

Utility, industry, and labor executives met with DOE Secretary Donald Hodel to present him with the details of the plan, and the department head was reported to have been "enthusiastic and impressed with the plan."

The Secretary said the plan would be reviewed quickly and in depth.

"We are very enthusiastic about the plan," said Gordon Corey, chairman of the task force of industry and investment banking firms that developed the plan.

"This is clearly a viable plan, fully supported by four leading investment banking firms," he said. "The plan shows the commitment of the private sector to keep America's energy option open."

Over $1.5 billion has been spent on the project to date. CRBR officials are hopeful that a construction permit will be issued this autumn.

The Top 100 electric utilities' 1982 operating performance

Robert Smock
Managing Editor

Peak demand dropped for the 100 largest investor-owned utilities in 1982 for the first time in decades as the economic recession cut deeply into utility operations.

That finding, plus across-the-board declines in fossil fuel consumption, were the most striking results of this year's operational analysis of the Top 100 utilities. Data were taken from each company's Uniform Statistical Report and are displayed on the large tables on the next four pages.

As shown in the peak-demand summary in Table 2, the sum of the noncoincident peaks for the group fell 1.8 percent in 1982. With generating capability rising slightly, overall reserve margins jumped back up into the comfortable range. The margin based on total system capability (which includes the net of each company's firm sales and firm purchases) climbed to nearly 29 percent. That measure of the reserve margin had fallen to 23 percent during the 1980 summer heat storm.

With electricity demand sluggish in 1983, it looks like the margin may grow even more. (It should be noted that the reserve margin for the entire electric industry is about 10 percentage points higher than that of the Top 100. The 100 largest investor-owned companies account for about 72 percent of electric utility industry generating capacity.)

Average load factor continued to deteriorate last year, falling to 57.5 percent—an understandable result considering the 10 percent drop in industrial kilowatt-hour consumption. (Total consumption for the Top 100 group was down by 2.2 percent for the year as reported in the financial analysis in the June *EL&P*.)

Looking at the individual company data, there were only 42 companies with increases in peak demand in 1982. That compares with 53 in 1981 and a whopping 82 in 1980. Of the 99 companies reporting peaks, 55 had decreases from the previous year and two showed no change.

The following companies had the largest declines in peak demand:

- Duquesne Light...down 14.4 percent,
- Pennsylvania Power & Light...down 13.8 percent,
- Iowa Public Service...down 13.4 percent,
- Detroit Edison...down 10.8 percent,
- Pacific Gas & Electric...down 10.7 percent,
- Cleveland Electric Illuminating...down 10.4 percent,
- Central Louisiana Electric...down 9.4 percent,
- Middle South Utilities...down 8.9 percent,
- Southern Co...down 8.1 percent,
- Kansas Gas & Electric...down 7.9 percent.

The list is dominated by utilities in the recession-hit central industrial states and in the South where a mild summer and the slump dampened peaks. The fall-off in demand during the '80s has been so large in the central industrial area that, if it declines again in 1983, peaks for some utilities could be back down to where they were 10 years ago.

Slumping peaks and rising generating capacity means rising reserve margins. The leaders in system reserve margin:

- Iowa Public Service...67 percent,
- Minnesota Power & Light...66 percent,
- Tucson Electric Power...64 percent,
- Public Service of New Mexico...55 percent,
- Consumers Power...53 percent,
- Madison Gas & Electric...53 percent,
- Sierra Pacific Power...53 percent,
- Wisconsin Public Service...52 percent,
- Cleveland Electric Illuminating...51 percent,
- Delmarva Power...51 percent.

This list has changed character considerably in the past six or eight years. Following the demand slump of the mid-70s reserve margins swelled for many eastern utilities, especially those hardest hit by rising oil prices. Now there's only one eastern utility in the list of the 10 utilities with the largest reserves.

TABLE 1
FOSSIL FUEL CONSUMPTION

	1981	Change	1982	Change
Coal (million tons)	469	+4.0%	461	-1.7%
Oil (million bbl)	334	-12.3%	232	30.5%
Gas (billion cu ft)	3152	+0.3%	2638	-16.3%

TABLE 2
PEAK DEMAND AND RESERVE MARGINS

	1981	Change	1982	Change
Seasonal peak (MW)	369,693	+1.2%	363,164	-1.8%
Total system capability (MW)	464,829	+3.2%	466,943	+0.5%
System reserve margin	25.7%		28.6%	
Total owned capability (MW)	433,032	+2.0%	439,419	+1.5%
Owned reserve margin	17.1%		21.0%	
Average load factor	58.6		57.5	

Winter peakers are strongly represented in the list of utilities with the largest increases in peak demand in 1982:

- Utah Power & Light...up 26.9 percent,
- Northern States Power...up 11.6 percent,
- Otter Tail Power...up 9.7 percent,
- Puget Sound Power...up 9.3 percent,
- Kentucky Utilities...up 8.7 percent,
- Pacific Power & Light...up 8.5 percent,
- Commonwealth Energy...up 7.1 percent,
- Interstate Power...up 5.8 percent,
- Duke Power...up 5.1 percent,
- Florida Power...up 5.1 percent.

There's no geographic pattern with this group. The only unusual aspect of the list is that 6 of the 10 are winter peakers.

Only 32 of the entire group of 100 have winter peaks. That, however, is a gain from the past two years, indicating that 1982's winter, though mild, was not as mild as the summer. (The apparently anomalous gain for Utah Power & Light was caused by the utility buying and reselling excess hydro power from the Pacific Northwest. The utility's own system showed a peak gain of only 1.2 percent.)

The rapid growth of the three Florida investor-owned utilities has abated somewhat. Last year, they accounted for three of the top four places in this list. This year only Florida Power made the top 10 and Tampa Electric was down 4.8 percent.

Slumping industrial demand continued to erode load factors. The average of the 1982 utility load factors fell to 57.5 percent from 1981's 58.6 percent. With overall industrial kilowatt-hour consumption off 10 percent it's surprising load factor didn't fall even more.

Oil disappearing

Data from the fuel consumption table, summarized in Table 1, show that the top 100 companies burned less coal, oil, and natural gas in 1982 than in 1981. Oil consumption by the group has declined by a huge 60 percent from the peak of 582 million barrels in 1978. The largest drop came last year, when only 232 million barrels were burned, down 31 percent from the previous year.

Among the utilities burning 1 million barrels a year or more, the ones showing the largest drops in 1982 oil consumption were:

- Pacific Gas & Electric...down 75 percent to 2,355,000 barrels,
- Delmarva Power...down 66 percent to 3,424,000,
- Virginia Electric & Power...down 52 percent to 3,178,000,
- New England Electric...down 45 percent to 8,721,000,
- Niagara Mohawk...down 40 percent to 8,294,000,
- Public Service of New Hampshire...down 34 percent to 2,673,000,
- Orange & Rockland...down 33 percent to 2,893,000,
- Pennsylvania Power & Light...down 30 percent to 5,635,000,
- Tampa Electric...down 29 percent to 3,010,000,

HEAT RATES AND FUEL CONSUMPTION

Company	Rank	Heat Rate (Btu/kWh)	Up or Down	Fuel Consumption: Coal (1000 tons)	Fuel Consumption: Oil (1000 bbl)	Fuel Consumption: Gas (1000 MCF)	Percent Change In: Coal	Percent Change In: Oil	Percent Change In: Gas
Commonwealth Energy System	1	9,650	D	0	6,909	2,295	–	–4	–9
Duke Power	2	9,666	U	14,824	1,199	25	–9	+795	–98
South Carolina Electric & Gas	3	9,977	D	4,046	280	369	–2	–81	–91
United Illuminating	4	9,979	D	0	7,344	0	–	–1	–
American Electric Power	5	9,983	U	36,837	1	187	–14	–	–61
Allegheny Power System	6	10,048	D	14,545	28	0	+2	–96	–
Detroit Edison	7	10,060	–	13,614	1,823	8,127	+3	–12	–34
New England Electric System	8	10,068	D	2,814	8,721	817	+247	–45	–67
Boston Edison	9	10,112	D	0	11,566	7,877	–	–6	+2474
Potomac Electric Power	10	10,141	D	6,155	2,315	0	–7	–25	–
Pennsylvania Power & Light	11	10,172	U	10,747	5,635	0	–22	–30	–
Central Hudson Gas & Electric	12	10,175	U	0	5,301	3,692	–	–2	–21
Union Electric	13	10,189	D	11,136	61	487	–2	+56	–19
Tampa Electric	14	10,208	D	4,179	3,010	0	+3	–29	–
Eastern Utilities Associates	15	10,210	U	0	3,874	0	–	–13	–
Washington Water Power	16	10,215	D	520	3	93	–19	–25	–98
Toledo Edison	17	10,228	D	2,080	12	60	–3	–54	–72
Houston Lighting & Power	18	10,255	U	6,278	566	427,319	–2	+8	–5
Public Service of Indiana	19	10,265	U	10,403	1	0	–5	–96	–
Dayton Power & Light	20	10,275	D	4,814	165	294	–1	+25	–58
Cincinnati Gas & Electric	21	10,276	D	6,888	682	147	–4	–89	–20
Consumers Power	22	10,285	D	5,233	312	1,609	–16	–91	–66
Illinois Power	23	10,289	U	6,805	100	154	–7	–19	–84
Central & South West	24	10,328	U	10,493	269	306,702	+23	+1929	–12
Long Island Lighting	25	10,362	D	0	15,360	21,678	–	–2	–44
Florida Power	26	10,383	U	2,170	10,737	12,257	+4	–27	+18
San Diego Gas & Electric	27	10,411	U	0	6,340	35,642	0	–23	–17
Niagara Mohawk Power	28	10,415	D	3,216	8,294	21,014	+11	–40	+148
Florida Power & Light	29	10,448	U	0	32,523	109,646	–	–27	+11
Central Illinois Light	30	10,454	D	2,255	0	69	–4	–	–1
Indianapolis Power & Light	31	10,462	U	4,944	48	0	–2	–26	–
Southern Company	32	10,469	U	34,256	3,751	6,416	–7	+1050	–48
Hawaiian Electric	32	10,469	D	0	10,311	0	0	–4	0
Southwestern Public Service	34	10,471	U	3,536	18	78,824	+9	–	–4
Carolina Power & Light	35	10,472	D	9,575	76	165	+1	–75	–82
Cleveland Electric Illuminating	36	10,475	D	6,613	160	0	+1	–26	–
Central Louisiana Electric	37	10,495	U	529	48	43,029	–	–41	–20
Orange & Rockland	38	10,580	U	0	2,893	13,893	–	–33	–15
Oklahoma Gas & Electric	39	10,598	D	5,553	19	132,857	+5	–24	–7
Atlantic City Electric	40	10,642	U	862	2,082	2,326	–3	–6	–19
Wisconsin Power & Light	41	10,659	U	2,824	36	79	+2	–	–48
New York State Electric & Gas	42	10,670	D	4,803	33	0	–1	–	–
Public Service Electric & Gas	43	10,704	D	3,666	5,811	44,746	+4	–20	–26
Central Illinois Public Service	44	10,754	U	4,861	6	0	–	–83	–
Kentucky Utilities	44	10,754	U	4,000	1	1	+1	–	–90
Iowa Public Service	46	10,757	U	1,932	19	329	–8	–9	–52
Louisville Gas & Electric	46	10,757	U	3,465	1	265	+2	–	–77
Baltimore Gas & Electric	48	10,764	D	1,865	4,098	616	+12	–14	–89
El Paso Electric	49	10,783	U	345	57	24,841	+10	–23	–28
Arizona Public Service	50	10,790	D	7,427	147	10,369	+4	+88	–36
Gulf States Utilities	51	10,793	U	645	417	247,195	–	–64	–11
Ohio Edison	52	10,822	U	9,657	91	0	–5	–21	–
Savannah Electric & Power	53	10,829	D	730	104	1,385	+14	–75	–11
Virginia Electric & Power	53	10,829	D	6,921	3,178	2,540	+15	–52	+80
Duquesne Light	55	10,853	D	4,839	108	0	–6	–112	–
General Public Utilities	56	10,861	U	7,154	1,046	19,862	–5	–29	+1
Northern States Power	57	10,874	U	7,065	40	334	–8	–86	–21
Public Service of Colorado	58	10,876	–	7,276	72	2,799	+20	–17	–67
Sierra Pacific Power	59	10,882	U	423	209	5,445	+1410	–2	–71
Public Service of New Hampshire	60	10,883	D	904	2,673	0	+5	–34	–
Rochester Gas & Electric	61	10,885	U	801	606	1,030	+1	+11	+2189
Wisconsin Public Service	62	10,903	U	2,613	40	169	+13	+11	+35
Northeast Utilities	63	10,908	U	404	10,616	3,325	+1396	–17	–9
Southern California Edison	64	10,913	U	5,059	4,453	257,328	+17	–81	+5
Philadelphia Electric	65	10,918	D	2,652	4,279	0	+4	+46	–100
Empire District Electric	66	10,958	U	1,091	10	144	+5	–47	–80
Missouri Public Service	67	10,965	D	1,235	5	258	–1	–17	–37
Pacific Gas & Electric	68	10,991	U	0	2,355	199,918	–	–75	–29
Minnesota Power & Light	69	10,992	D	2,879	0	0	–21	–100	–100
Delmarva Power & Light	70	11,004	U	2,000	3,424	4,077	–7	–66	–2
Middle South Utilities	71	11,031	U	3,063	1,458	289,230	+14	–78	–4
Central Maine Power	72	11,056	U	0	2,327	0	–	–14	–
Texas Utilities	73	11,063	D	29,946	695	304,857	+4	+141	–2
Kansas Gas & Electric	73	11,063	D	2,846	75	27,577	–3	–63	–14
Nevada Power	75	11,098	D	2,514	36	6,983	+4	–29	–69
Southern Indiana Gas & Electric	76	11,104	U	1,813	14	115	–12	–95	–86
Kansas City Power & Light	77	11,138	U	5,273	120	2,579	–13	+20	–29
Iowa-Illinois Gas & Electric	78	11,145	U	1,691	18	884	–2	+13	–34
Commonwealth Edison	79	11,146	D	15,681	7,176	6,070	–1	–25	–18
Tucson Electric Power	80	11,170	U	2,757	1	7,054	–	–99	–64
Wisconsin Electric Power	81	11,175	–	5,037	165	3,150	–7	–14	–21
Consolidated Edison	82	11,431	D	0	21,312	73,517	–	–18	+3
Central Vermont Public Service	83	11,208	U	0	36	0	–	–18	–
Northern Indiana Public Service	84	11,254	U	4,473	262	2,351	–10	–32	–40
Madison Gas & Electric	85	11,264	D	791	10	1,018	+3	+43	+2
Public Service of New Mexico	86	11,296	U	3,617	74	3,503	+45	+957	–60
Montana Power	87	11,299	U	1,423	267	923	–20	–91	+111
Central Telephone & Utilities	88	12,321	U	506	20	9,602	–3	–20	–14
Utah Power & Light	89	11,338	U	7,140	60	3,010	+5	–21	–13
Puget Sound Power & Light	90	11,346	U	335	2	17	–80	–78	–53
Portland General Electric	91	11,349	U	524	1	34	–51	–	–82
Iowa Resources	92	11,378	U	1,852	19	252	–12	–27	–24
Interstate Power	93	11,386	U	1,995	27	867	–4	–37	–39
Idaho Power	94	11,398	U	2,213	427	5	+1	+8440	–69
Pacific Power & Light	95	11,427	U	10,633	90	0	–	–17	–100
Iowa Electric Light & Power	96	11,538	–	948	20	280	+14	–5	–13
Kansas Power & Light	97	11,583	D	4,715	217	7,982	+5	–54	–36
Otter Tail Power	98	11,803	D	2,208	3	0	+2	–40	–
Montana-Dakota Utilities	99	12,653	D	1,487	9	65	+3	–25	–71
Texas-New Mexico Power	100	14,547	U	0	0	492	–	–100	–58

- General Public Utilities...down 29 percent to 1,046,000.
- Florida Power...down 27 percent to 10,737,000.
- Florida Power & Light...down 27 percent to 32,523,000.
- Potomac Electric Power...down 25 percent to 2,315,000.

All but Pacific Gas & Electric, which benefitted from a good hydro year, are on the East Coast and many achieved the cuts in oil usage by converting oil-burning capacity to coal. VEPCO, NEES, Florida Power, and PEPCO have all completed conversion projects. Most of the others are in the process of converting or considering it, which should reduce oil consumption even more in future years.

TABLE 3
GENERATING CAPABILITY (MW)

	1981	Change	1982	Change
Conventional steam and combined cycle	336,588	+1.4%	339,714	+0.9%
Hydro and pumped storage	23,415	-3.5%	25,148	+7.4%
Gas turbines and internal combustion	36,632	+5.5%	36,940	+0.8%
Nuclear	43,222	+7.8%	43,131	-0.2%
Total	439,857	+2.0%	444,933	+1.2%

The list of the largest oil consumers shows a similar pattern. Here's how oil burners, ranked by the amount of oil burned in 1982, reduced oil consumption last year:

- Florida Power & Light...down 27 percent to 32,523,000 barrels.
- Consolidated Edison...down 18 percent to 21,312,000.
- Long Island Lighting...down 2 percent to 15,360,000.
- Boston Edison...down 6 percent to 11,566,000.
- Florida Power...down 27 percent to 10,737,000.
- Northeast Utilities...down 17 percent to 10,616,000.
- Hawaiian Electric...down 4 percent to 10,311,000.

TABLE 4
TOP 20 GENERATING UNITS—BY HEAT RATE

	Unit	Capacity
1.	Marshall 3	630 MW
2.	Marshall 4	630
3.	Belews Creek 2	1120
4.	Belews Creek 1	1120
5.	Marshall 1	320
6.	Marshall 2	320
7.	Gorgas 10	693
8.	Trenton Channel 9	500
9.	Bay Shore 4	215
10.	Canal 1	568
11.	Morgantown 2	582
12.	John Amos 2	800
13.	Mercer 2	306
14.	Brayton Pt. 3	643
15.	Montour 2	750
16.	Bay Shore 1	136
17.	Bay Shore 3	142
18.	Big Sandy 1	260
19.	Fort Myers 2	367
20.	Monroe 1	750

- Niagara Mohawk...down 40 percent to 8,294,000.
- United Illuminating...down 17 percent to 7,344,000.
- Commonwealth Energy...down 4 percent to 6,909,000.

Although many of the companies on this list are working on converting oil-burning capacity to coal, only Northeast Utilities has accomplished a conversion so far. These utilities achieved their oil reductions through reduced operation of oil-burning plants due to reduced energy demand and through increased purchased power. Niagara Mohawk, for example, bought a substantial amount of energy from Ontario Hydro, and Florida Power & Light purchased energy from the Southern Co., its coal burning neighbor to the north.

The other major fuel-consumption change that shows up in the figures is the huge, 16 percent drop in natural gas consumption. This reflects the rapid runup in the price of gas, at a time when the prices of the other fossil fuels were flat, and the end of the "gas bubble." The gas bubble really broke in 1981, but the effect didn't show up in fuel use figures until last year. The "bubble" was a perceived excess of natural gas in the years 1978, 1979, and 1980 that was used by the Carter administration to fight oil imports, a major policy objective of that administration. The Carter DOE and FERC urged electric utilities to substitute natural gas for imported oil wherever possible.

Utilities responded. The Top 100 figures show oil use dropping from, as mentioned above, the high of 582 million barrels in 1978 to 232 million last year while gas use climbed from 2.7 trillion cubic ft in 1978 to 3.15 trillion in 1981.

But the Reagan administration showed no interest in curbing imported oil, oil prices started dropping in 1981, and gas prices climbed even fas-

Utility	Unit heat rate
Duke Power	8901
Duke Power	8910
Duke Power	8930
Duke Power	8966
Duke Power	8991
Duke Power	9032
Southern Company	9039
Detroit Edison	9066
Toledo Edison	9127
Commonwealth Energy	9180
Potomac Electric Power	9295
American Electric Power	9305
Public Service Electric & Gas	9318
New England Electric System	9320
Pennsylvania Power & Light	9351
Toledo Edison	9362
Toledo Edison	9375
American Electric Power	9379
Florida Power & Light	9391
Detroit Edison	9392

PEAK DEMAND AND CAPABILITY

Company	Season Peak MW	% Change	Winter (W) or Summer (S)	Total System Capacity MW (at time of peak)	Total System Reserve %	Owned Capacity MW (at time of peak)	Owned Reserve %	Load Factor %
Allegheny Power System	5,720	+2.8	W	7,240	27	7,590	33	61.3
American Electric Power	19,301	−7.0	W	21,610	12	20,900	8	61.8
Arizona Public Service	2,899	−1.0	S	3,440	19	3,240	12	55.7
Atlantic City Electric	1,264	–	S	1,531	21	1,480	17	55.3
Baltimore Gas & Electric	3,924	+1.4	S	5,015	28	4,862	24	53.6
Boston Edison	2,181	+5.0	S	2,901	33	2,658	22	56.8
Carolina Power & Light	6,602	+3.1	W	8,180	24	8,105	23	55.0
Central & South West	9,154	–	S	11,876	30	12,066	32	56.4
Central Hudson Gas & Electric	666	+3.9	S	803	21	924	39	62.5
Central Illinois Light	973	−3.0	S	1,272	31	1,272	31	51.9
Central Illinois Public Service	1,846	−2.6	S	2,390	29	2,270	23	57.0
Central Louisiana Electric	974	−9.4	S	1,294	33	1,611	65	55.9
Central Maine Power	1,259	+4.1	W	1,073	−15	1,465	16	64.1
Central Telephone & Utilities	586	−6.3	S	NA	NA	661	13	NA
Central Vermont Public Service	392	−0.8	W	426	9	70	−82	60.7
Cincinnati Gas & Electric	2,960	−5.7	S	4,201	42	4,079	38	59.1
Cleveland Electric Illuminating	3,090	−10.4	S	4,675	51	4,599	49	65.3
Commonwealth Edison	13,072	−1.7	S	17,158	31	16,164	24	56.2
Commonwealth Energy Systems	665	+7.1	S	880	32	223	66	59.8
Consolidated Edison	7,302	+3.4	S	10,487	44	9,422	29	47.5
Consumers Power	4,445	−5.5	S	6,817	53	6,668	50	66.6
Dayton Power & Light	2,219	+4.6	W	2,697	22	2,701	22	55.1
Delmarva Power & Light	1,523	−3.3	S	2,303	51	2,303	51	58.5
Detroit Edison	6,394	−10.8	S	8,569	34	8,300	30	61.7
Duke Power	11,145	+5.1	W	13,377	20	13,234	19	56.8
Duquesne Light	2,158	−14.4	W	3,217	49	3,192	48	61.7
Eastern Utilities Associates	681	+3.0	S	862	27	555	−19	39.3
El Paso Electric	744	+1.1	S	985	32	920	24	60.5
Empire District Electric	505	−0.2	S	636	26	629	25	52.8
Florida Power & Light	10,885	+1.4	W	11,023	1	13,399	23	53.0
Florida Power	5,347	+5.1	W	5,535	4	5,255	−2	42.9
General Public Utilities	6,442	+3.7	W	8,473	32	8,251	28	–
Gulf States Utilities	5,164	−6.8	S	7,208	40	6,298	22	67.8
Hawaiian Electric	1,117	+1.7	W	1,587	42	1,559	40	70.7
Houston Lighting & Power	10,594	+0.5	S	12,969	22	11,669	10	63.0
Idaho Power	2,089	−1.3	S	2,692	29	2,512	20	64.0
Illinois Power	2,951	−5.0	S	3,886	32	3,818	29	57.6
Indianapolis Power & Light	1,925	+1.5	S	2,528	31	2,528	31	55.7
Interstate Power	760	+5.8	S	904	19	902	19	66.0
Iowa Electric Light & Power	920	+0.7	S	1,109	21	1,008	10	55.2
Iowa-Illinois Gas & Electric	936	+3.2	S	1,331	42	1,334	42	50.6
Iowa Public Service	715	−13.4	S	1,192	67	1,178	65	53.9
Iowa Resources	1,097	−5.8	S	1,518	38	1,132	3	47.9
Kansas City Power & Light	2,167	+2.1	S	2,764	28	2,774	28	45.4
Kansas Gas & Electric	1,548	−7.9	S	1,945	26	1,976	28	52.6
Kansas Power & Light	1,719	−0.4	S	2,314	35	2,210	29	49.0
Kentucky Utilities	2,330	+8.7	W	2,951	27	2,678	15	53.2
Long Island Lighting	3,045	−2.8	S	3,767	24	3,721	22	51.4
Louisville Gas & Electric	1,662	−6.8	S	2,250	35	2,154	30	52.9
Madison Gas & Electric	387	+4.0	S	594	53	594	53	54.3
Middle South Utilities	10,382	−8.9	S	14,258	37	13,862	34	60.0
Minnesota Power & Light	1,090	−6.5	W	1,811	66	1,393	28	66.0
Missouri Public Service	691	−0.1	S	897	30	897	30	43.3
Montana-Dakota Utilities	323	−3.0	S	403	25	403	25	NA
Montana Power	1,208	+1.0	W	1,484	23	1,105	−9	67.9
Nevada Power	1,420	−0.2	S	1,792	26	1,500	6	49.9
New England Electric System	3,171	+0.9	S	4,301	36	3,964	25	59.7
New York State Electric & Gas	2,091	−4.7	W	2,898	39	1,780	15	65.1
Niagara Mohawk Power	5,512	−1.9	W	7,280	32	5,309	−4	65.6
Northeast Utilities	4,050	−1.9	W	5,595	38	6,323	56	59.8
Northern Indiana Public Service	2,150	−1.5	S	3,086	44	2,686	25	66.5
Northern States Power	5,222	+11.6	S	6,552	25	5,988	15	55.3
Ohio Edison	4,073	−1.8	W	5,868	44	5,686	40	64.4
Oklahoma Gas & Electric	4,440	+0.4	S	5,554	25	5,360	21	50.6
Orange & Rockland	726	+3.1	S	1,021	41	1,011	39	49.6
Otter Tail Power	532	+9.7	W	621	17	619	16	57.0
Pacific Gas & Electric	12,215	−10.7	S	16,127	32	11,190	−8	66.6
Pacific Power & Light	4,147	+8.5	W	3,857	−7	5,142	24	60.0
Pennsylvania Power & Light	4,489	−13.8	W	6,546	46	6,470	44	53.2
Philadelphia Electric	5,691	−0.7	S	7,297	28	7,648	34	59.2
Portland General Electric	2,794	+4.0	W	3,890	39	2,129	−24	56.4
Potomac Electric Power	4,146	−0.1	S	5,364	29	5,364	29	50.0
Public Service of Colorado	2,892	+2.6	S	3,400	18	2,857	−1	65.4
Public Service of Indiana	3,923	−0.5	W	5,222	33	5,374	37	53.3
Public Service of New Hampshire	1,176	−2.2	W	1,552	32	1,268	8	58.2
Public Service of New Mexico	957	−3.5	S	1,485	55	1,475	54	70.5
Public Service Electric & Gas	7,042	+0.1	S	8,995	28	8,995	28	51.2
Puget Sound Power & Light	3,558	+9.3	W	3,948	11	1,260	−66	48.5
Rochester Gas & Electric	996	−5.0	S	1,499	50	1,147	15	65.1
San Diego Gas & Electric	2,046	−3.2	S	2,790	36	2,363	15	39.9
Savannah Electric & Power	462	−7.4	S	649	40	600	30	57.2
Sierra Pacific Power	662	+2.6	W	1,011	53	688	4	70.8
South Carolina Electric & Gas	2,463	−3.7	S	3,359	36	3,359	36	57.0
Southern California Edison	13,149	−4.3	S	14,957	14	13,302	−1	55.5
Southern Company	17,840	−8.1	S	26,435	48	24,433	37	59.8
Southern Indiana Gas & Electric	739	−5.1	S	897	21	1,012	37	52.8
Southwestern Public Service	2,385	−7.6	S	3,487	46	3,498	47	64.2
Tampa Electric	2,258	−4.8	W	2,499	11	2,499	11	53.5
Texas-New Mexico Power	NA	NA	NA	NA	NA	NA	NA	NA
Texas Utilities	13,204	+1.8	S	17,957	36	17,862	35	56.0
Toledo Edison	1,355	+3.0	W	1,790	32	1,738	28	62.0
Tucson Electric Power	953	−3.9	S	1,566	64	978	3	54.5
Union Electric	5,842	−2.0	S	7,187	23	6,565	12	50.4
United Illuminating	952	+0.3	S	1,294	36	1,294	36	56.7
Utah Power & Light	3,320	+26.9	S	2,729	−18	2,764	−17	63.6
Virginia Electric & Power	8,879	+2.8	W	10,912	23	10,289	15	55.5
Washington Water Power	1,557	+1.1	W	1,993	28	1,226	−21	51.0
Wisconsin Electric Power	3,194	−2.9	S	4,261	33	4,337	36	64.8
Wisconsin Power & Light	1,252	−0.8	S	1,777	42	1,631	30	65.0
Wisconsin Public Service	1,101	−2.7	W	1,674	52	1,663	51	74.9

TYPE OF GENERATION IN THE SYSTEM

	Fossil			Hydro & Pump Storage			Combustion Turbines			Nuclear		
Company	MW	%	Last Year Change MW	MW	%	Last Year Change MW	MW	%	Last Year Change MW	MW	%	Last Year Change MW
Allegheny Power System	7,521	99	-7	62	1	–	0	–	–	0	–	–
American Electric Power	18,355	85	–	812	4	+24	188	1	-129	2150	10	–
Arizona Public Service	2,723	84	-102	6	–	–	511	16	–	0	–	–
Atlantic City Electric	841	55	–	0	–	–	368	24	+2	319	21	–
Baltimore Gas & Electric	2,506	51	–	0	–	–	717	15	0	1650	34	–
Boston Edison	1,806	66	-21	0	–	–	275	10	-30	670	24	–
Carolina Power & Light	4,481	58	-20	214	3	–	1018	13	–	2045	26	-200
Central & South West	12,060	100	+522	0	–	–	0	–	–	0	–	–
Central Hudson Gas & Electric	837	90	+3	45	5	-1	43	5	-10	0	–	–
Central Illinois Light	1,202	97	+19	0	–	–	32	3	+2	0	–	–
Central Illinois Public Service	2,775	99	+533	0	–	–	3	1	–	0	–	–
Central Louisiana Electric	1,443	98	+120	0	–	–	23	2	-2	0	–	–
Central Maine Power	742	67	+13	319	29	+19	44	4	–	0	–	–
Central Telephone & Utilities	573	85	+40	0	–	–	98	15	-12	0	–	–
Central Vermont Public Service	14	14	–	39	40	+2	44	46	–	0	–	–
Cincinnati Gas & Electric	3,549	88	+41	0	–	–	475	12	–	0	–	–
Cleveland Electric Illuminating	3,786	82	+39	330	7	+25	62	1	–	447	10	-6
Commonwealth Edison	9,674	58	-574	624	4	–	1639	10	–	4851	29	–
Commonwealth Energy System	1,021	94	–	0	–	–	62	6	–	0	–	–
Consolidated Edison	6,570	69	+37	0	–	–	2050	22	+64	849	9	–
Consumers Power	4,192	64	-107	1089	17	+1	477	7	–	803	13	–
Dayton Power & Light	2,490	92	+18	0	–	–	210	8	+27	0	–	–
Delmarva Power & Light	1,876	79	+28	0	–	–	170	7	-18	319	13	–
Detroit Edison	6,847	83	-80	918	11	–	530	6	–	–	–	–
Duke Power	7,423	56	–	1452	11	+892	599	5	–	3760	28	–
Duquesne Light	2,453	78	+15	0	–	–	306	10	+5	385	12	-48
Eastern Utilities Associates	507	91	–	0	–	–	48	9	–	0	–	–
El Paso Electric	922	93	+24	0	–	–	69	7	-16	0	–	–
Empire District Electric	419	67	–	16	2	–	195	31	–	0	–	–
Florida Power & Light	8,779	68	–	0	–	–	1979	15	–	2109	16	–
Florida Power	3,425	58	+630	0	–	–	1718	29	+92	752	13	–
General Public Utilities	4,101	50	–	307	4	–	1487	18	–	2356	29	–
Gulf States Utilities	6,175	99	+378	0	–	–	90	1	+90	0	–	–
Hawaiian Electric	1,344	86	+23	0	–	–	215	14	-4	0	–	–
Houston Lighting & Power	11,022	90	+615	0	–	–	1174	10	-182	0	–	–
Idaho Power	858	33	-6	1675	65	+18	50	2	–	0	–	–
Illinois Power	3,626	95	–	2	–	–	178	5	-8	0	–	–
Indianapolis Power & Light	2,463	97	–	0	–	–	65	3	–	0	–	–
Interstate Power	847	94	–	0	–	–	55	6	–	0	–	–
Iowa Electric Light & Power	500	50	+1	0	–	–	158	16	-23	350	35	–
Iowa-Illinois Gas & Electric	878	66	-16	3	–	–	67	5	-60	384	29	–
Iowa Public Service	984	84	-19	0	–	–	194	16	-29	0	–	–
Iowa Resources	856	76	-94	0	–	–	275	24	–	0	–	–
Kansas City Power & Light	2,404	87	-110	0	–	–	370	13	–	0	–	–
Kansas Gas & Electric	1,953	99	–	0	–	–	23	1	–	0	–	–
Kansas Power & Light	1,973	85	+53	0	–	–	341	15	–	0	–	–
Kentucky Utilities	2,595	97	–	24	1	–	69	2	–	0	–	–
Long Island Lighting	2,672	72	–	0	–	–	1049	28	–	0	–	–
Louisville Gas & Electric	2,342	96	+354	0	–	–	108	4	–	0	–	–
Madison Gas & Electric	412	69	-9	0	–	–	90	15	-1	92	16	-1
Middle South Utilities	11,688	85	–	69	1	–	411	3	–	1694	12	–
Minnesota Power & Light	1,285	92	–	109	8	+1	0	–	–	0	–	–
Missouri Public Service	601	67	–	0	–	–	296	23	–	0	–	–
Montana-Dakota Utilities	348	30	–	0	–	–	814	70	–	0	–	–
Montana Power	579	52	–	520	47	–	5	1	–	0	–	–
Nevada Power	1,062	69	+2	0	–	–	468	31	+100	0	–	–
New England Electric System	2,665	67	-4	1177	30	-16	131	3	3	0	–	–
New York State Electric & Gas	1,731	97	+11	38	2	–	10	1	–	0	–	–
Niagara Mohawk Power	3,668	71	-71	608	12	-42	310	6	–	610	12	–
Northeast Utilities	2,485	43	-4	1264	22	-2	501	9	-58	1529	26	–
Northern Indiana Public Service	2,435	91	–	10	1	–	241	9	–	0	–	–
Northern States Power	3,294	54	+140	220	4	+16	1101	18	+2	1539	25	–
Ohio Edison	5,097	90	+190	0	–	–	164	3	-190	425	7	–
Oklahoma Gas & Electric	5,255	99	-46	0	–	–	69	1	–	0	–	–
Orange & Rockland	902	90	–	30	3	-4	74	7	–	0	–	–
Otter Tail Power	523	83	-1	4	1	+1	102	16	-2	0	–	–
Pacific Gas & Electric[†]	8,281[†]	75	-116	2393	22	+16	394	4	+7	0	–	–
Pacific Power & Light	2,982	74	-15	976	24	–	26	1	–	27	1	–
Pennsylvania Power & Light	5,785	46	–	146	2	–	539	8	–	0	–	–
Philadelphia Electric	3,389	43	-47	1392	18	–	1336	17	-26	1816	23	–
Portland General Electric	990	37	–	601	22	-60	355	13	–	729	27	–
Potomac Electric Power	4,773	81	+298	0	–	–	1123	19	+561	0	–	–
Public Service of Colorado	2,458	86	-68	25	1	-90	187	7	–	200	7	–
Public Service of Indiana	5,567	95	+469	55	1	–	221	4	–	0	–	–
Public Service of New Hampshire	1,100	86	+6	60	5	–	117	9	3	0	–	–
Public Service of New Mexico	1,453	99	-601	0	–	–	20	1	-40	0	–	–
Public Service Electric & Gas	4,308	48	-120	165	2	–	2705	30	+14	1817	20	–
Puget Sound Power & Light	508	40	-5	310	24	+13	455	36	–	0	–	–
Rochester Gas & Electric	601	52	-4	47	4	–	29	3	–	470	41	–
San Diego Gas & Electric	1,943	82	–	0	–	–	333	14	–	87	4	–
Savannah Electric & Power	537	88	–	0	–	–	72	12	+10	0	–	–
Sierra Pacific Power	591	86	+18	12	2	–	87	12	-1	0	–	–
South Carolina Electric & Gas	2,418	72	+20	756	23	–	185	5	–	0	–	–
Southern California Edison	11,498	86	–	877	7	–	620	5	+22	349	3	–
Southern Company	18,657	76	+19	2200	9	-22	1165	5	-19	2398	10	+14
Southern Indiana Gas & Electric	877	87	–	0	–	–	135	13	–	0	–	–
Southwestern Public Service	3,448	99	+508	0	–	–	50	1	-6	0	–	–
Tampa Electric	2,380	94	+39	0	–	–	158	6	–	0	–	–
Texas-New Mexico Power	39	78	-5	0	–	–	11	22	–	0	–	–
Texas Utilities	17,856	99	–	0	–	–	6	1	–	0	–	–
Toledo Edison	1,233	71	+14	0	–	–	77	4	+11	428	25	-2
Tucson Electric Power	1,348	86	–	0	–	–	218	14	–	0	–	–
Union Electric	5,648	86	+11	631	10	–	283	4	–	0	–	–
United Illuminating	1,215	98	+11	0	–	–	22	2	–	0	–	–
Utah Power & Light	2,620	95	–	125	5	-1	19	1	–	0	–	–
Virginia Electric & Power	6,145	59	170	326	3	–	550	5	111	3309	32	4
Washington Water Power	197	9	–	1892	86	+946	101	5	–	0	–	–
Wisconsin Electric Power	2,984	69	-2	75	2	-3	288	7	–	990	23	–
Wisconsin Power & Light	1,206	74	+2	42	3	+1	178	11	+1	211	13	+2
Wisconsin Public Service	1,244	73	-34	56	3	-1	187	11	+27	212	12	–

[†] Includes geothermal and process steam

ter as the gas supply industry approached deregulation. Utilities responded again, holding gas use constant in 1981 and slashing it last year by 16 percent. The Top 100 burned less gas in 1982 than they did in 1978.

The trend toward lower gas use also shows up among the traditionally gas-fired utilities. These companies have slowly been reducing gas consumption by switching to coal, building nuclear plants, and purchasing outside energy. Here's what happened last year with the biggest gas users in the Top 100:

- Houston Lighting & Power...down 5 percent to 427 billion cubic ft,
- Central & Southwest...down 12 percent to 307 billion,
- Texas Utilities...down 2 percent to 305 billion,
- Middle South Utilities...down 4 percent to 289 billion,
- Southern California Edison...up 5 percent to 257 billion,
- Gulf States Utilities...down 11 percent to 247 billion,
- Pacific Gas & Electric...down 29 percent to 200 billion,
- Oklahoma Gas & Electric...down 7 percent to 133 billion,
- Florida Power & Light...up 11 percent to 110 billion,
- Southwestern Public Service...down 4 percent to 79 billion.

Coal use was down slightly, for the first time in many years, as the economic slump in the Appalachian coal areas outweighed the gains in the Southwest where gas burners are switching to coal. Here's how the largest coal users fared in 1982:

TABLE 5
SYSTEM HEAT RATE LEADERS—FOSSIL-FUELED BOILERS ONLY

	Utility	Heat rate
1.	Duke Power	9,337
2.	Commonwealth Energy	9,648
3.	American Electric Power	9,861
4.	Consumers Power	9,921
5.	Boston Edison	10,042
6.	Allegheny Power	10,048
7.	Detroit Edison	10,050
8.	New England Electric	10,071
9.	Florida Power & Light	10,114
10.	Central Hudson	10,172

- American Electric Power...down 14 percent to 37 million tons,
- Southern Co...down 7 percent to 34 million tons,
- Texas Utilities...up 4 percent to 30 million tons,
- Commonwealth Edison...down 1 percent to 16 million tons,
- Duke Power...down 9 percent to 15 million tons,
- Allegheny Power...up 2 percent to 15 million tons,
- Detroit Edison...up 3 percent to 14 million tons,
- Union Electric...down 2 percent to 11 million tons,
- Pennsylvania Power & Light-

Power plant thermal efficiency continued its long-term decline in 1982.

...down 22 percent to 11 million tons,
- Central & Southwest...up 23 percent to 10 million tons.

Efficiency dropping

The overall decline in thermal efficiency continued in 1982. Only 41 of the Top 100 companies managed to improve their heat rates last year. That compares to 43 in 1981 and 53 in 1980. The median system heat rate in 1982 was 10790, up from 10725 in '81, 10655 in '80, and 10634 in '79.

It's difficult to understand how industry efficiency could have declined by 1.5 percent in those four years. There was almost no new nuclear capacity coming on line and very little new coal capacity with efficiency-robbing pollution control equipment to account for the decline. In fact, a lot of old, low-efficiency capacity was retired.

The company heat rate rankings show little change. At the top of the system heat rate table the only big changes were South Carolina Electric & Gas Co.'s move from 12th place in 1981 to 3rd place last year on the strength of an improvement in system heat rate from 10174 to 9977 and PEPCO's move from 15th to 10th, based on improving system heat rate from 10225 to 10141.

Likewise, on Table 5, the fossil-boiler heat rate table, there were no significant changes. (This table is included to screen out the effects of nuclear and gas turbine capacity on system heat rate in order to more fairly compare utility boiler systems. It should be noted that the absolute heat rate is not that meaningful a number. Changes in a utility's heat rate over time tell more about it than the absolute number or the ranking. Also, external factors such as the imposition of pollution control hardware can have a stronger negative effect on heat rates than internal programs aimed at improving efficiency.)

The unit rankings are shown on Table 4. Again, there is little change with Duke Power's Marshall and Belews Creek units leading the list. However, a comparison of this list with last year's shows that unit heat rates are, puzzlingly, slightly higher.

The remaining large tables on generating capability and T&D lines show no significant trends. The only class of generating capacity to change much in 1982 was hydro with a 1733 MW gain boosting the total 7 percent. Only 3000 MW of new coal-fired capacity was put on line in 1982 and the nuclear total actually declined slightly due to some minor deratings of operating units.

TRANSMISSION AND DISTRIBUTION LINES IN OPERATION

	Transmission				Distribution							
					Overhead				Underground			
Company	189 kV & Up (circuit miles)	Miles Added	Below 189 kV (circuit miles)	Miles Added	22 kV & Up (pole miles)	Miles Added	Below 22 kV (pole miles)	Miles Added	22 kV & Up (cable miles)	Miles Added	Below 22 kV (cable miles)	Miles Added
Allegheny Power System	858	6	3,222	–1592	4,520	1558	47,685	234	5	4	2,174	264
American Electric Power	21,215*	–256	–	–	95,262*	789	–	–	5,460*	88	–	–
Arizona Public Service	2,302†	105	2,239	25	0	–	10,271	93	0	–	4,641	307
Atlantic City Electric	64	–	1,163	2	5,873*	9*	–	–	651*	34*	–	–
Baltimore Gas & Electric	489	–	590	1	733	–2	NA	–	159	10	NA	–
Boston Edison	160	–	199	–	3,369*	2*	–	–	7,084*	–351*	–	–
Carolina Power & Light	2,534	97	3,063	17	36,020*	336*	–	–	2,410*	–	–	–
Central & South West	1,113	24	13,841	92	209	15	50,729	877	0	–	4,628	284
Central Hudson Gas & Electric	76	–	603	78	44	–	6,216	4	–	–	658	43
Central Illinois Light	48	–	286	–	627	–	5,646	–	7	–	1,590	–
Central Illinois Public Service	305	–	4,276	–	–	–	8,264*	18*	–	–	560*	31*
Central Louisiana Electric	298	16	767	2	8,044	30	1,742	5	166*	7*	–	–
Central Maine Power	2,247*	–1	–	–	16,231*	+219	–	–	364*	5	–	–
Central Telephone & Utilities	2,924*	22*	–	–	6,478*	–8*	–	–	577*	46*	–	–
Central Vermont Public Service	0	–	615	1	6,925*	33*	–	–	78*	5*	–	–
Cincinnati Gas & Electric	380	0	1,379	–48	484	–126	8,881	+6	20	+3	1,542	+36
Cleveland Electric Illuminating	256	–	2,002	–12	–	–	9,419	10	–	–	4,753	147
Commonwealth Edison	2,383	–2	2,441	25	35,569*	38*	–	–	19,753*	308*	–	–
Commonwealth Energy System	60	–	293	9	1,363	41	3,294	–5	640	30	1,789	–99
Consolidated Edison	329	–	22	–	347^	12^	25,758^	–20^	6,305	40	58,144	69
Consumers Power	1,864	–	7,919	–	1,114	–	45,690	–	3,136*	–2430*	–	–
Dayton Power & Light	474	29	1,287	1	NA	–	NA	–	NA	–	NA	–
Delmarva Power & Light	264	–	1,071	2	4,587	–12	2,453	3	1,898	98	663	448
Detroit Edison	968	+69	4,404	–55	–	–	29,402	+47	–	–	6,757	+122
Duke Power	2,941	+54	9,075	54	8,780	95	45,577	441	1,397	69	2,839	155
Duquesne Light	132	–	511	–3	386	386	6,068	–368	360	360	1,983	–313
Eastern Utilities Associates	359*	–	–	–	3,229*	–	–	–	845*	–	–	–
El Paso Electric	461	109	654	–	1,519	342	2,874†	–	45	45	631	631
Empire District Electric	0	–	1,180	1	0	–	4,479	35	0	–	196	7
Florida Power & Light	2,416	135	2,261	23	31,830*	725*	0	–	9,001*	869*	0	–
Florida Power	1,378	34	2,719	–52	0	–	15,445*	11*	0	–	5,207*	32*
General Public Utilities	2,044	15	4,417	9	4,420	131	40,143	–22	1,156	40	9,840	303
Gulf States Utilities	1,019	88	3,598	–74	957	48	17,823	354	286	36	1,467	21
Hawaiian Electric	0	0	1,259	+11	0	0	3,863	+61	0	0	1,858	+72
Houston Lighting & Power	712	14	2,421	57	768	56	16,964	–128	598	53	3,517	293
Idaho Power	1,473†	+5†	3,241†	–3†	3,776	186	13,147	–107	116	+33	4,007	+113
Illinois Power	449	–	2,335	9	1,371	10	16,354	55	4	–	942	16
Indianapolis Power & Light	380	–	617	–7	0	–	4,605	22	0	–	3,283	95
Interstate Power	69	–	2,644	4	NA	–	NA	–	0	–	466	15
Iowa Electric Light & Power	67	–	3,598	379	0	–	4,690	–4	0	–	1,460	32
Iowa-Illinois Gas & Electric	264	–	623	10	0	–	3,268	9	0	–	1,004	45
Iowa Public Service	180	–	2,208	–25	NA	–	NA	–	NA	–	NA	–
Iowa Resources	330	–	1,333	–	0	–	10,247	667	0	–	1,822	87
Kansas City Power & Light	295	–	1,331	4	8,814*	11*	–	–	3,867*	398*	–	–
Kansas Gas & Electric	565	–	1,585	–13	7,705*	–73*	–	–	1,518*	88*	–	–
Kansas Power & Light	668	59	3,579	24	0	–	12,074	139	0	–	362	13
Kentucky Utilities	433	–458	4,133	–8686	0	–	13,737	155	0	–	0	–
Long Island Lighting	0	–	1,024	12	15,064*	–199*	–	–	NA	–	NA	–
Louisville Gas & Electric	131	–	879	+130	87	–643	3,236	654	0	–	1,690*	32*
Madison Gas & Electric	124	–	165	–	0	–	1,073	3	0	–	472	22
Middle South Utilities	2,108	5	7,338	27	5,498	–	63,544	2267	1,428	–275	2,319	116
Minnesota Power & Light	606†	–	1,495†	16†	744	–	3,887	–18	3°	–	726°	121°
Missouri Public Service	58†	–	1,260†	4†	0	–	4,639	31	0	–	450	23
Montana-Dakota Utilities	260	–	2,868	19	0	–	2,866	36	0	–	1,445	148
Montana Power	1,084	–	5,459	78	0	–	12,429	179	0	–	933°	39°
Nevada Power	581	45	451	9	0	–	2,590	464	0	–	2,215	243
New England Electric System	602	19	1,994	–89	784	81	16,788	811	194	–1	6,776	441
New York State Electric & Gas	749	–	3,841	–34	1,944	120	29,905	39	1°	–181°	185°	184°
Niagara Mohawk Power	1,116	42	8,153	6	107,253*^	–29*^	–	–	6,418*	99*	–	–
Northeast Utilities	450	–	1,615	9	20,677*	110*	–	–	5,148*	149*	–	–
Northern Indiana Public Service	301	1	2,578	9	0	–	7,637	2	0	–	575	14
Northern States Power	1,431	13	5,448	898	25,049*	2494*	–	–	9,236*	423*	–	–
Ohio Edison	574	–	4,872	10	–	–	24,460	27	–	–	2,533	90
Oklahoma Gas & Electric	811	6	3,550	10	18,805*	270*	0	–	4,509*	207*	0	–
Orange & Rockland	80	5	480	–	0	–	4,567	21	0	–	788	65
Otter Tail Power	294	–	5,314	254	165	–3	718	–78	4	–1464	1,557	128
Pacific Gas & Electric	6,390	3	11,377	10	81,408*	508*	–	–	9,170°	401°	–	–
Pacific Power & Light	7,054*	28*	–	–	28,604*	243*	–	–	9,614*	–	–	–
Pennsylvania Power & Light	1,312	45	0	–	2,339	10	46,236	297	10	–	3,840	273
Philadelphia Electric	673	–	392	–17	57	–	11,664	16	17	–	14,265	648
Portland General Electric	544	34	944	–10	9,070*	41*	–	–	3,628*	486*	–	–
Potomac Electric Power	773	6	26	–	3	–285	854	–3702	303	–398	5,414	2574
Public Service of Colorado	2,993*	57*	–	–	12,921*	21*	–	–	3,738*	278*	–	–
Public Service of Indiana	1,450	64	4,017	–5	0	–	18,209	–88	0	–	1,886	157
Public Service of New Hampshire	224	–	1,459	–	9,300*	68*	–	–	424*	18*	–	–
Public Service of New Mexico	1,098	188	847	4	4,310*	71*	–	–	–	–	1,550*	116*
Public Service Electric & Gas	682	2	1,796	–2	14*	–	–	–	109	–	18,739	602
Puget Sound Power & Light	320†	–	1,321†	–	12,087*	995*	–	–	4,055*	164*	–	–
Rochester Gas & Electric	0	–	713	–3	0	–	6,598	–2	0	–	4,045	48
San Diego Gas & Electric	210	5	1,094	6	0	–	7,218	23	0	–	5,375	230
Savannah Electric & Power	38	–	62	8	281	–	2,255	43	–	–	–	–
Sierra Pacific Power	895	–	2,318	92	6,107*	65*	–	–	1,867*	407*	–	–
South Carolina Electric & Gas	740	28	2,336	1	6,956	69	5,774	47	41	–	1,391	88
Southern California Edison	5,216	286	6,192	13	44,332*	–3*	–	–	38,385*	1731*	–	–
Southern Company	5,394	–1468	19,424	2016	83,285*	+636*	–	–	9,332*	814*	–	–
Southern Indiana Gas & Electric	0	–	804	9	0	–	3,171	–1	0	–	582	24
Southwestern Public Service	1,098	196	3,785	46	13,306*	–	0	–	777*	–	0	–
Tampa Electric	352	3	732	17	0	–	6,312	47	0	–	1,377	62
Texas-New Mexico Power	20	–	1,538	15	–	–	7,498*	–	–	–	275*	–
Texas Utilities	3,461	200	8,661	25	2,481	86	46,704	–3468	666	80	6,086	261
Toledo Edison	159	–	1,114	–	7,589*	–*	–	–	687*	–*	–	–
Tucson Electric Power	1,664*	227*	–	–	6,279*	221*	–	–	2,134*	136*	–	–
Union Electric	909	–	2,407	–	1,208	4	12,822	53	335	1	6,447	134
United Illuminating	6	–	89	–	2	–	2,990	11	3	–	1,164	–9
Utah Power & Light	2,082†	244†	5,514†	39†	14,309*	203*	–	–	2,231°*	113°*	–	–
Virginia Electric & Power	2,515	–22	3,014	19	37,919*	103*	–	–	10,627*	408*	–	–
Washington Water Power	538†	–†	1,516†	1†	574	12	8,695	21	0	–	1,152	55
Wisconsin Electric Power	631	1	1,794	43	22,088*	–396*	–	–	7,213*	219*	–	–
Wisconsin Power & Light	107	–	2,744	–	16,649*	55*	–	–	0	–	937	–160
Wisconsin Public Service	124	–	1,578	–2	16,315*	63	–	–	2,930*	191	–	–

*Total—All voltage levels †Pole miles ^Wire miles °Conduit bank miles

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Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

Peak demand up 4%; weather is major factor

BARRINGTON, IL—Peak demand rose 4% over that of a year ago, according to the annual survey conducted by *Electric Light & Power*. Data from 57 electric companies comprises this year's statistical base, representing a substantial nationwide sample of electricity demand.

The 57 companies reported an aggregate seasonal peak demand of 326,763 megawatts for 1983, compared with 314,363 MW reported in 1982. This represents a growth of 4.0% for 1983.

The telephone survey was conducted by *EL&P* staff editors in mid-September when most utilities could be expected to have passed their summer peaks. Looking at the non-coincident summer peak load for 49 of these companies reveals an aggregate megawatt figure of 296,963 for 1983, compared with a corresponding figure reported by these same companies in 1982 of 275,983. These figures show an increase in summer peak demand for 1983 of 7.6%, measurably above the 4.0% seasonal peak.

Preliminary figures of an independent estimate of non-coincident summer peak demand by the Edison Electric Institute (EEI) project an increase of 6% to 8% for 1983.

As one measure of survey accuracy, last year *EL&P* reported (October issue) that non-coincident summer peak demand dropped 3.6% compared to 1981. Final figures released by EEI showed that non-coincident summer peak demand for the entire electric utility industry dropped 3.1%.

Weather is main factor

Peak demand at midwestern utilities increased precipitously during the summer and was the strongest factor in boosting national seasonal electricity demand. Cincinnatti Gas & Electric rose 12.0%; Commonwealth Edison was up 11.1%; Consumers Power, jumped 7.2%; and Detroit Edison, was up 10.5%. Illinois Power, Iowa Electric Light and Power, and Iowa Resources increased 11.1%, 6.0% and 10.1%, respectively.

Increases were 7.3%, 10.9%, and 5.6%, respectively, for Kansas City Power & Light, Kansas Gas & Electric, and Kansas Power & Light.

Electric companies in Indiana, Minnesota, and Wisconsin experienced similar increases.

These peak demand expansions correspond to that area of the United States designated by the National Weather Service as experiencing very extreme heat this summer.

In general, the National Oceanic and Atmospheric Administration (NOAA) said the 1983 meteorological summer (June through August) was the 17th hottest since that agency began keeping records in 1931. Although the month of August was the hottest on record, the overall summer temperatures were moderated by a relatively cool June, NOAA spokesperson Tina Saarlas said.

The heat of the summer was felt most severely in the Central Mississippi Valley. This includes the area bounded on the West by Kansas and Nebraska, and on the East by Indiana and Kentucky. Also experiencing severe heat this summer was a belt along the East Coast, running south from New Jersey to the Carolinas.

According to the NOAA, 220 people died and $10 billion in crops were lost as a result of the extreme heat. The midwest area suffering the extreme heat includes the Corn Belt.

Some economic increases

While weather seemed to be responsible for a good portion of peak demand increases for 1983, there were unquestionably some increases due to economic recovery.

The Middle South Utilities system, for example, attributed virtually all of its 5.0% peak demand increase to economic recovery. Arkansas Power & Light Co., Louisiana Power & Light Co., Mississippi Power & Light Co., and New Orleans Public Service, Inc., are all part of the MSU system.

Continued on page 3

Seabrook 2: project viability threatened

It looks extremely rocky for Seabrook-2 this day;
Participants are dropping out; it costs too much to pay.

MANCHESTER, N.H.—As with Casey at the Bat, who gave it three good tries before anxious onlookers, the Seabrook-2 nuclear plant increasingly looks as if it will go down swinging.

In mid-September the joint owners of the Seabrook station voted unanimously to reduce work on unit 2 to the lowest feasible level until unit 1 is completed. Earlier they voted down a proposal to cancel the unit entirely.

The resolution to minimize work on unit 2 stipulates that the reduction is to remain in effect until fuel loading for unit 1 occurs, unless the plant is cancelled before that. Construction on the first unit is now 81 percent complete and is scheduled to be finished in December, 1984.

Robert J. Harrison, president of Public Service of New Hampshire said his company still supports completion of unit 2, but recent developments have necessitated reduction of the construction work.

"Completing both Seabrook units is still the best option for PSNH, its customers, stockholders and employees, but we will continue to consider all options," he said.

PSNH, with 35.5 percent ownership in the two-unit plant, is the lead utility in a consortium of electric companies and public power entities that are sponsoring the project. Unit 2 is currently 23 percent complete and has been scheduled to be finished in July, 1987.

There is little joy in Manchester

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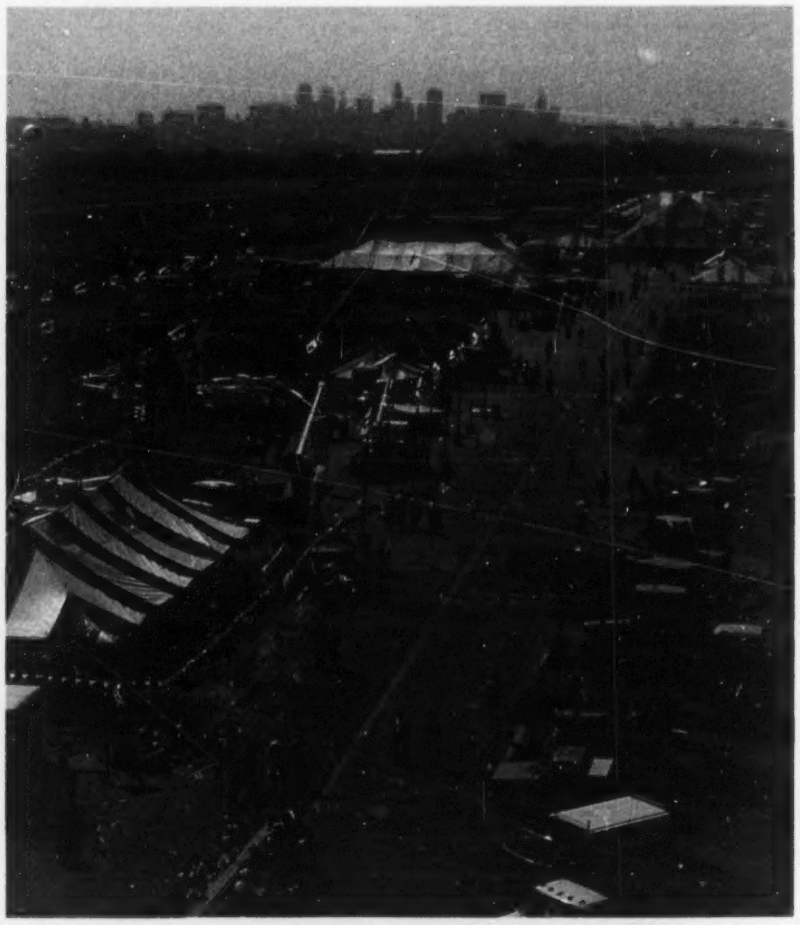

K.C. hosts ICUEE

Approximately 7,200 people attended the three-day International Construction and Utility Equipment Exposition outside of Kansas City in August. Held every two years, the show attracts exhibitors and visitors from around the world. More details and a close-up view of the show can be found on p.32 in the Transmission/Distribution section of the magazine.

EPRI cancels its superconducting generator funds

PALO ALTO, CA—The board of directors of the Electric Power Research Institute cancelled the group's financial participation in the half-completed, $42 million project at Westinghouse aimed at building a commercial, 300-MVA superconducting generator. Westinghouse said it has halted work on the machine as a result of the EPRI move.

The pull-out came about half way through the six-year project with about $21 million already spent, half by each partner. Westinghouse said it had completed design and engineering and was just beginning manufacture. The machine, which would have been the first commercial sized superconducting generator in the world, was slated for installation at TVA's Gallatin station in 1985.

The move by EPRI's utility-executive, policy-setting board disappointed both EPRI staff members and researchers at Westinghouse. "Those of us closest to the project technologically are disappointed," said John Dougherty, vice president of EPRI in charge of the electrical systems group. "The project would have resulted in a good line of new generators, but there were other considerations," he added.

Westinghouse's statement said, "Westinghouse is disappointed at the decision of the EPRI board of directors to cancel their joint sponsorship of the commercial superconducting generator program... Our understanding is that EPRI's decision resulted from budget limitations coupled with shifting R&D priorities."

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News Analysis

Structural concerns darken WPPSS-2 showcase status

Rebar placement deficiencies threaten February, 1983 startup

Dan Utroska
Associate Editor

RICHLAND, WA—Ever since the Bonneville Power Administration announced it would underwrite completion of nuclear unit 2 of the Washington Public Power Supply System, all parties have been closely monitoring the plant's construction progress.

BPA said it would come up with $150 million now estimated to finish construction on the $3.2 billion plant. The federal marketing agency offered its infusion of cash when default of the supply system appeared certain.

WPPSS now has formally defaulted (see *EL&P*, September 1983, page 1) and the supply system's nuclear plant number 2 has emerged as a showcase project. BPA and WPPSS want to demonstrate that even though the grand design of constructing and operating five large nuclear plants has fallen through, at least one of the plants can be brought on-line, operate efficiently, and produce revenues.

"Number 2 is a credibility builder for the supply system," notes Wu Chin, project engineer at the plant.

Critics, however,—particularly participants, such as public utility districts, municipals, and public power districts in the Northwest—are eyeing developments at WNP-2 to help them decide what action to take on units 1 and 3. WNP-1 is to be mothballed for 5 years, and WNP-3 has been unilaterally deferred by the supply system, much to the dismay of four Northwest investor-owned utilities that collectively own 30 percent of the plant.

The four private companies, who want the three-quarters complete plant finished so they can begin recovering their investment, have gone to court to protect their interests.

Participants in the ill-fated WPPSS nuclear plants 4 and 5 are, for the most part, the same participants in units 1, 2, and 3. Although these public power entities have, as of September, 1983, won the legal right to withdraw from their earlier contractual commitment to "take or pay" for units 4 and 5, they appear to accept the completion of unit 2 as a *fait accompli.*

Even though the billing schemes for units 1, 2, and 3 are qualitatively different from those for 4 and 5, there has been speculation that participants in these earlier units might want out of the projects, possibly arguing coersion, excessively inflated demand forecasts on the part of BPA, or advancing similar claims.

"What happens to WNP-2 is going to tell...a lot about what we ought to do with units 1 and 3," Tacoma attorney Albert Malanca told *EL&P*. Malanca represented 12 major Northwest utilities in the litigation over units 4 and 5. Collectively, these utilities owned more than 50 percent of the two now-cancelled plants. This same group owns a nearly equivalent share of units 1, 2, and 3.

Malanca said that he knew of no active or formal opposition to the completion of WNP-2. "Number 2 is here," he said, emphasizing that this acknowledgement on the part of the participants represented "a very common sense approach."

But, he added, "A lot [of persons] are looking to unit 2 to see where additional nuclear power fits into the Northwest power picture." He said there were a number of questions about the startup of WNP-2, noting that precedents already existed for nuclear plants becoming near operational and then stalling because of technical difficulties.

The main test of the validity of the billing arrangements between BPA and the participants in WNP-1, WNP-2, and WNP-3 is the action filed in November, 1982 in U.S. District Court by the City of Springfield, Oregon. The city asked the court to determine whether the participants in the projects had the legal authority to enter into "net billing agreements".

Unlike the determination of the Washington State Supreme Court, which said that, because of state law, participants were not bound to honor the take-or-pay contracts for WNP-4 and WNP-5, a U.S. district court has held that parties to the net billing agreements did have the authority to enter into these accords. The Oregon court ruling is now under appeal.

Continued on page 15

Peak demand . . . from page 1

Noting that the national economy expanded at an annualized rate of 9.2% in the second quarter of 1983, and that national unemployment had dropped from 10.8% in December 1982 to 9.5% in July 1983, MSU chairman and president Floyd W. Lewis observed, "All this positive economic activity has been good for the country, and it has resulted in a rapid increase in the demand for electric energy in the area served by the Middle South Utilities System."

Lewis said that the level of peak demand had exceeded by 6% that level earlier forecasted for the system's service area. The 10,891 MW peak demand experienced by MSU (see table) had not been anticipated until 1985.

This surge in electricity demand occurred despite the absence of record-setting temperatures, MSU said. In fact, the utility reports that temperatures have been averaging as much as two to three degrees below normal in part of the Middle South area. Noting that moderate weather in parts of the system's service area directly offset heat wave conditions in other parts, MSU declared, "It appears that the increase in customer demand is due to the economic recovery."

Energy demand also rises

Growing peak demand has also been accompanied by growing energy demand, as data collection neared the end of the third quarter. According to statistics compiled by EEI, electric output for the first 37 weeks of 1983 was 1,640 billion kilowatt-hours, up 1.6% over the same period in 1982.

Electricity output is the measure of electricity generation minus such elements such as line losses experienced in transmission, electricity theft, and power company usage.

Week-to-week changes in output since the beginning of the year have shown a steady growth pattern, moving from early declines of power demand, as compared to the same period in 1982, to gradual increases. Positive weekly figures (compared to 1982) first appeared in March, then see-sawed, finally becoming regularly positive in mid-June.

Since then growth has been steady, moving into double-digit weekly growth figures in mid-August. Also in August the year-to-date output figures, as compared to 1982, turned positive for the first time. They have remained positive since that time.

PEAK DEMAND

Utility Co.	1983 season peak—MW	1982 season peak—MW	Percent change
Allegheny Power System	5,036	5,720 (W)	−12.0
American Electric Power	19,427	19,301 (W)	+0.9
Arizona Public Service	2,918	2,899	+0.9
Baltimore Gas & Electric	4,079	3,924	+4.0
Boston Edison	2,233	2,181	+2.4
Carolina Power & Light	6,926	6,602 (W)	+4.9
Central & Southwest	9,567	9,154	+4.5
Cincinnati Gas & Electric	3,314	2,960	+12.0
Cleveland Electric Illuminating	3,366	3,090	+12.0
Commonwealth Edison	14,517	13,072	+11.1
Consolidated Edison	8,447	7,302	+15.7
Consumers Power	4,763	4,445	+7.2
Detroit Edison	7,067	6,394	+10.5
Duke Power	11,554	10,602	+9.0
Duquesne Light	2,184	2,158	−1.2
Florida Power & Light	10,653	10,885 (W)	−2.1
Florida Power Corp.	4,701 (W)	5,347 (W)	−12.1
General Public Utilities	6,140	6,442 (W)	−4.7
Gulf States Utilities	5,353	5,164	+3.7
Houston Lighting & Power	10,959	10,594	+3.5
Idaho Power	2,091	2,089	+0.1
Illinois Power	3,279	2,951	+11.1
Iowa Electric Light & Power	975	920	+6.0
Iowa Resources	1,208	1,097	+10.1
Kansas City Power & Light	2,324	2,167	+7.3
Kansas Gas & Electric	1,716	1,548	+10.9
Kansas Power & Light	1,815	1,719	+5.6
Kentucky Utilities	2,399	2,330 (W)	+3.0
Long Island Lighting	3,105	3,045	+2.0
Middle South Utilities	10,891	10,382	+5.0
Montana Power	1,142 (W)	1,208 (W)	−5.5
New England Electric System	3,250	3,171	+2.5
New York State Elec. & Gas	2,091 (W)	2,193 (W)	−4.7
Niagara Mohawk Power	5,223 (W)	5,512 (W)	−5.2
Northeast Utilities	4,074	4,050 (W)	+0.6
Northern Indiana Public Service	2,356	2,150	+9.6
Northern States Power	5,360	5,222	+2.6
Ohio Edison	4,148	4,073	+1.8
Oklahoma Gas & Electric	4,702	4,440	+5.9
Pacific Gas & Electric	13,243	12,215	+8.4
Pacific Power & Light	3,606 (W)	4,147 (W)	−13.0
Pennsylvania Power & Light	4,489 (W)	5,207 (W)	−13.8
Philadelphia Electric	5,879	5,691	+3.3
Portland General Electric	2,408 (W)	2,764 (W)	−12.9
Potomac Electric Power	4,283	4,146	+3.3
Public Service of Indiana	3,818	3,707	+3.0
Public Service Elec. & Gas	7,244	7,042	+2.9
Rochester Gas & Electric	1,037	996	+4.1
South Carolina Elec. & Gas	2,700	2,463	+9.6
Southern California Edison	13,464	13,149	+2.4
Southern Company	22,201	19,532	+13.7
Texas Utilities	14,029	13,204	+6.2
Union Electric	6,550	6,105	+7.3
Utah Power & Light	2,334	2,318	+0.7
Virginia Electric & Power	9,404	8,879 (W)	+5.9
Wisconsin Electric Power	3,555	3,194	+11.3
Wisconsin Public Service	1,166	1,101 (W)	+5.9
TOTALS	**326,763**	**314,363**	**+4.0**

FEMA oks Indian Point drills

NEW YORK—Officials of the Federal Energy Management Agency say that "significant deficiencies" in the emergency evacuation plans of the two Indian Point nuclear reactors have been overcome.

FEMA Public Information Officer Mary Ann Jackson said August drills in Westchester and Rockland Counties went well. A final report on the drills will be issued later in the year, said FEMA.

Earlier in the year, FEMA had said it could not guarantee the safety of residents in a 10-mile zone around the plant because of inadequate emergency evacuation plans. Rockland County refused to participate in an emergency drill, until it could come up with a plan of its own. There were also transportation problems in nearby Westchester County.

After the transportation problem was solved and New York state intervened with an alternate plan for Rockland County, the NRC voted in June to keep the plants operating. (See *EL&P* July 1983, p.3).

FEMA spokeswoman Jackson said everything went well during a four-hour transportation drill held in Westchester. The next day, said Jackson, a 7-hour night exercise was held in Rockland using the state's alternative plan. She said some of the police and ambulance drivers of Rockland did participate in the drill.

"There were no glaring problems," said Jackson, pointing out that FEMA is satisfied with the drills.

Full-scale exercises are required once a year at each nuclear plant site.